BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

DOCKETS UE-240004 & UG-240005 (Consolidated)

CROSS-EXAMINATION EXHIBIT OF ANN E. BULKLEY
ON BEHALF OF THE
WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL
PUBLIC COUNSEL UNIT

EXHIBIT AEB-__X

Transcript of Chair Powell's Press Conference - December 13, 2023

October 28, 2024

EXH. AEB-18
DOCKETS UE-240004/UG-240005
2024 PSE GENERAL RATE CASE
WITNESS: ANN E. BULKLEY

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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SEVENTEENTH EXHIBIT (NONCONFIDENTIAL) TO THE PREFILED DIRECT TESTIMONY OF

ANN E. BULKLEY

ON BEHALF OF PUGET SOUND ENERGY

FEBRUARY 15, 2024

Transcript of Chair Powell's Press Conference
December 13, 2023

CHAIR POWELL. Good afternoon. My colleagues and I remain squarely focused on our dual mandate to promote maximum employment and stable prices for the American people.

As we approach the end of the year, it's natural to look back on the progress that has been made toward our dual-mandate objectives. Inflation has eased from its highs, and this has come without a significant increase in unemployment. That's very good news. But inflation is still too high, ongoing progress in bringing it down is not assured, and the path forward is uncertain. As we look ahead to next year, I want to assure the American people that we're fully committed to returning inflation to our 2 percent goal. Restoring price stability is essential to achieve a sustained period of strong labor market conditions that benefit all.

Since early last year, the FOMC has significantly tightened the stance of monetary policy. We've raised our policy interest rate by 5¼ percentage points and have continued to reduce our securities holdings at a brisk pace. Our actions have moved our policy rate well into restrictive territory, meaning that tight policy is putting downward pressure on economic activity and inflation, and the full effects of our tightening likely have not yet been felt.

Today, we decided to leave our policy interest rate unchanged and to continue to reduce our securities holdings. Given how far we have come, along with the uncertainties and risks that we face, the Committee is proceeding carefully. We will make decisions about the extent of any additional policy firming and how long policy will remain restrictive based on the totality of the incoming data, the evolving outlook, and the balance of risks. I will have more to say about monetary policy after briefly reviewing economic developments.

Recent indicators suggest that growth of economic activity has slowed substantially from the outsized pace seen in the third quarter. Even so, GDP is on track to expand around

2½ percent for the year as a whole, bolstered by strong consumer demand as well as improving supply conditions. After picking somewhat over the—up somewhat over the summer, activity in the housing sector has flattened out and remains well below the levels of a year ago, largely reflecting higher mortgage rates. Higher interest rates also appear to be weighing on business fixed investment. In our Summary of Economic Projections (SEP), Committee participants revised up their assessments of GDP growth this year but expect growth to cool, with the median projection falling to 1.4 percent next year.

The labor market remains tight, but supply and demand conditions continue to come into better balance. Over the past three months, payroll job gains averaged 204,000 jobs per month, a strong pace that is nevertheless below that seen earlier in the year. The unemployment rate remains low at 3.7 percent. Strong job creation has been accompanied by an increase in the supply of workers. The labor force participation rate has moved up since last year, particularly for individuals aged 25 to 54 years, and immigration has returned to pre-pandemic levels.

Nominal wage growth appears to be easing, and job vacancies have declined. Although the jobs-to-workers gap has narrowed, labor demand still exceeds the supply of available workers. FOMC participants expect the rebalancing in the labor market to continue, easing upward pressures on inflation. The median unemployment rate projection in the SEP rises somewhat from 3.8 percent at the end of this year to 4.1 percent at the end of next year.

Inflation has eased over the past year but remains above our longer-run goal of 2 percent. Based on the consumer price index and other data, we estimate that total PCE prices rose 2.6 percent over the 12 months ending in November and that, excluding the volatile food and energy categories, core PCE prices rose 3.1 percent.

The lower inflation readings over the past several months are welcome, but we will need to see further evidence to build confidence that inflation is moving down sustainably toward our goal.

Longer-term inflation expectations appear to remain well anchored, as reflected in a broad range of surveys of households, businesses, and forecasters, as well as measures from financial markets. As is evident from the SEP, we anticipate that the process of getting inflation all the way to 2 percent will take some time. The median projection in the SEP is 2.8 percent this year, falls to 2.4 percent next year, and reaches 2 percent in 2026.

The Fed's monetary policy actions are guided by our mandate to promote maximum employment and stable prices for the American people. My colleagues and I are acutely aware that high inflation imposes significant hardship, as it erodes purchasing power, especially for those least able to meet the higher costs of essentials like food, housing, and transportation. We are highly, highly attentive to the risks that high inflation poses to both sides of our mandate, and we are strongly committed to returning inflation to our 2 percent objective.

As I noted earlier, since early last year, we have raised our policy rate by 5¼ percentage points, and we have decreased our securities holdings by more than $1 trillion. Our restrictive stance of monetary policy is putting downward pressure on economic activity and inflation. The Committee decided at today's meeting to maintain the target range for the federal funds rate at 5¼ to 5½ percent and to continue the process of significantly reducing our securities holdings.

While we believe that our policy rate is likely at or near its peak for this tightening cycle, the economy has surprised forecasters in many ways since the pandemic, and ongoing progress—sorry—ongoing progress toward our 2 percent inflation objective is not assured. We are prepared to tighten policy further if appropriate. We're committed to achieving a stance of monetary policy that is sufficiently restrictive to bring inflation sustainably down to 2 percent over time and to keeping policy restrictive until we're confident that inflation is on a path to that objective.

In our SEP, FOMC participants wrote down their individual assessments of an appropriate path for the federal funds rate based on what each participant judges to be the most likely scenario going forward. While participants do not view it as likely to be appropriate to raise interest rates further, neither do they want to take the possibility off the table. If the economy evolves as projected, the median participant projects that the appropriate level of the federal funds rate will be 4.6 percent at the end of 2024, 3.6 percent at the end of 2025, and 2.9 percent at the end of 2026, still above the median longer-term rate.

These projections are not a Committee decision or plan; if the economy does not evolve as projected, the path of policy will adjust as appropriate to foster our maximum-employment and price-stability goals.

In light of the uncertainties and risks, and how far we have come, the Committee is proceeding carefully. We will continue to make our decisions meeting by meeting, based on the totality of the incoming data and their implications for the outlook for economic activity and inflation, as well as the balance of risks. In determining the extent of any additional policy firming that may be appropriate to return inflation to 2 percent over time, the Committee will take into account the cumulative tightening of monetary policy, the lags with which monetary policy affects economic activity and inflation, and economic and financial developments. We remain committed to bringing inflation back down to our 2 percent goal and to keeping longer-term inflation expectations well anchored. Restoring price stability is essential to set the stage for achieving maximum employment and stable prices over the longer run.

To conclude: We understand that our actions affect communities, families, and businesses across the country. Everything we do is in service to our public mission. We at the Fed will do everything we can to achieve our maximum-employment and price-stability goals.

Thank you. I look forward to your questions.

MICHELLE SMITH. Let's go to Chris Rugaber.

CHRISTOPHER RUGABER. Thank you. Chris Rugaber at Associated Press. I wanted to ask, how should we interpret the addition of the word "any" before "additional . . . firming" in the statement? I mean, does that mean that you're pretty much done with rate hikes and the Committee has shifted away from a tightening bias and toward a more neutral stance?
Thank you.

CHAIR POWELL. So—specifically on "any": We do say that "in determining the extent of any additional policy firming that may be appropriate," so "any additional policy firming"—that sentence. So we added the word "any" as an acknowledgement that we believe that we are likely at or near the, the peak rate for this cycle. Participants didn't write down additional hikes that we believe are likely, so that's what we wrote down. But participants also didn't want to take the possibility of further hikes off the table. So that's really what we were thinking.

MICHELLE SMITH. Steve.

STEVE LIESMAN. Steve Liesman, CNBC. Happy holidays, Mr. Chairman. Fed Governor Chris Waller said that if inflation continues to fall, then the Fed in the next several months could be cutting interest rates. I wonder if you could comment on whether you agree with Fed Governor Waller on that, that the Fed would become more restrictive if it didn't cut rates if inflation fell. Thank you, sir.

CHAIR POWELL. So, of course, I don't comment on, on any other officials, even those who work at the Fed. But I'll—but I'll try to answer your question more broadly. So the way—the way we're looking at it is, is really this. When we started out, right, we said the first question is, how fast to move, and we moved very fast. The second question is, you know, really, how high to raise the policy rate? And that's really the question that we're still on here. We're, we're very focused on that, as I—as I mentioned. People generally think that we're at or near that and, and think it's not likely that we will hike, although they don't take that possibility off the table. So that's—when you get to that question, and that's your answer, there's a natural—naturally, it begins to be the next question, which is when it will become appropriate to begin dialing back the amount of policy restraint that's in place.

So that's really the next question, and that's what people are thinking about and, and talking about. And I would just say this. We are seeing, you know, strong growth that is—that appears to be moderating; we're seeing a labor market that is coming back into balance by so many measures; and we're seeing inflation making real progress. These are the things we've been wanting to see. We can't know. We still have a ways to go. No one is declaring victory. That would be premature. And we can't be guaranteed of this progress [continuing]. So we're, we're moving carefully in making that assessment of whether we need to do more or not. And that's, that's really the question that we're on. But, of course, the other question, the question of when will it become appropriate to begin dialing back the amount of policy restraint in place, that, that begins to come into view and is clearly a discussion—topic of discussion out in the world and also a discussion for us at our meeting today.

STEVE LIESMAN. Can you give some color as to the nature of that discussion today? Thank you.

CHAIR POWELL. Sure. So it, it comes up in this way today. Everybody wrote down an SEP forecast. So many people mentioned what their—what their rate forecast was. And there was no back-and-forth, no attempt to sort of reach agreement like, “This is what I wrote down; this is what I think,” that kind of thing, and a preliminary kind of a discussion like that. Not everybody did that, but many people did. And then, and I would say, there’s a general expectation that this will be—this will be a topic for us, looking ahead. That, that’s really what happened in today’s meeting. I can’t do the head count for you in real time. But that’s generally what happened today.

STEVE LIESMAN. Thank you.

MICHELLE SMITH. Let’s go to Rachel.

RACHEL SIEGEL. Hi, Chair Powell. Rachel Siegel from the *Washington Post.* Thanks for taking our questions. At this point, can you confidently say that the economy has avoided a recession and isn’t heading for one now? And if the answer is “no,” I’m curious about what you’d still be looking for. Thanks.

CHAIR POWELL. I think you can say that there’s little basis for thinking that the economy is in a recession now. I would say that.

I think there’s, there’s always a probability that, that there will be a recession in the next year, and it’s a meaningful probability no matter what the economy is doing. So it’s always a real possibility. The question is, is it—so it’s a possibility here. I have always felt, since the beginning, that there was a possibility, because of the unusual situation, that the economy could cool off in a way that enabled inflation to come down without the kind of large job losses that have often been associated with high inflation and tightening cycles. So far, that’s what we’re seeing. That’s what many forecasters, on and off the Committee, are seeing. This result is not guaranteed. It is—it is far too early to declare victory. And there are certainly risks. It's certainly possible that, that the economy will behave in an unexpected way. It has done that repeatedly through the post—in the post-pandemic period. Nonetheless, where we are is, is we see the things that I—that I mentioned.

RACHEL SIEGEL. I'm curious, if you're looking back on the past year, you talked about "navigating by the stars under cloudy skies." Can you talk about some of the ways in which the economy surprised you most this year, where you thought it would behave in one way and had to pivot to respond? Thanks.

CHAIR POWELL. So I think forecasters generally, if you go back a year, were very broadly forecasting a recession for this year, for 2023. And not only did that not happen—that includes Fed forecasters and really, essentially, all forecasters; a very high proportion of forecasters predicted very weak growth or a recession—not only did that not happen, we actually had a very strong year, and that was a combination of, of strong demand but also of real gains on the supply side.

So this was the year when labor force participation picked up, where immigration picked up, where the distortions to supply and demand from the pandemic—you know, the shortages and the bottlenecks—really began to unwind. So we had significant supply-side gains with strong demand, and we got what looks like a 2½ percent-plus, or a little more than that, growth year at a time when potential growth this year might even have been higher than that, just because of the healing on the supply side. So that was a surprise to just about everybody.

I think the inflation forecast is roughly, roughly what people wrote down a year ago, but in a very different setting. And I would say the labor market, because of the stronger growth, has also been significantly better. If you look back at the SEP from a year ago, there was a significant increase in, in unemployment. It didn't really happen. We're still at 3.7 percent. So we've seen, you know, strong growth, still a tight labor market but one that's coming back into balance with the—with support from the supply side, a greater supply of labor. It's a—you know, that's, that's what we see, and I think that combination was, was not anticipated broadly.

MICHELLE SMITH. Howard.

HOWARD SCHNEIDER. Thanks. Howard Schneider with Reuters, and thanks for taking the questions. I, I wonder if you could give a little more color or detail on what—on what motivates the lower rates next year, whether it's a coincidence, for example, that the spread between PCE inflation, core inflation, and the federal funds rate stays constant over the year. Are you simply calibrating against the fall in prices, in the price level that you're expecting, in the rate of inflation that you're expecting as opposed to supporting the economy?

CHAIR POWELL. Nothing quite that mechanical is happening. The SEP really is, is a bottoms-up—built from the bottom up, right? So I think people are looking at what's happening in the economy. And I think if you look at the big difference from September in the SEP, [it is that] the expectations for inflation this year, both headline and core, have come down, you know, really significantly in three months. That's a big piece of, of this. At the same time, [real GDP] growth has turned out to be very strong in the third quarter. [Now it] is slowing, we believe, as, as appropriate. And we've got—we've had several labor market reports, which suggest, again, significant progress toward greater balance across a very—a broad range of indicators. You're seeing so many of the indicators coming back to normal, not all of them. But so I think that people look at that, and they write down their—basically, each individual writes down a forecast and a rate forecast that goes with that forecast. We tabulate them and, and publish it. And so it's not—it isn't—you ask about real rates, I take it?

HOWARD SCHNEIDER. Yes.

CHAIR POWELL. You know, that's—that is—that is something that we're very conscious of, and aware of, and monitor, and it's certainly a big part of—it's a part of how we think about things. But, really, it's broader financial conditions that matter. And, as you well know, it's so hard to know exactly, you know, what the—what the real rate is or exactly how tight policy is at any given time. So you couldn't follow that like it was a rule and think that you would get the right answer all the time, but it's certainly something that we're focused on. And, indeed, if you look at the projections, I think the expectation would be that the real rate is declining as we—as we move forward.

HOWARD SCHNEIDER. It sounds like the discussion—if I could follow up—has, has already kind of begun. I'm wondering, just related to, to Steve's question, how the—how the tactics of this play out given the slowing of inflation and the fact that the deeper you get into 2024, the closer you get to a presidential election. Do you want to front-load this, in other words?

CHAIR POWELL. Yeah. No, we—we're—we don't think about political events. We don't think about politics. We think about what's the right thing to do for the economy. The minute we start thinking about those things—you know, we just can't do that. We have to think, what's the right thing? We'll do the things that we think are right for the economy at the time we—when we think is the right time. That's what we'll always do.

So I mentioned we're moving carefully. One of the things we're moving carefully about is that decision over—that assessment, really—over whether, whether we've done enough, really. And you see that people are not writing down rate hikes. That's, that's us thinking that we have done enough but not, not feeling that really strongly, confidently and not wanting to take the possibility of a rate hike off the table. Nonetheless, it's not the base case anymore, obviously, as it was, you know, 60, 90 days ago. So that's, that's how we're—that's how we're approaching things. And, and, you know, as I mentioned, we wrote down this SEP, and it talks about—people have individual assessments of when it will be appropriate to, you know, to start to dial back on, on the tight policy we have in place, and that's a discussion we'll be having going forward. But that's another assessment that we're going to make very carefully, so as time goes forward.

MICHELLE SMITH. Nick.

NICK TIMIRAOS. Nick Timiraos of the *Wall Street Journal.* Chair Powell, you've argued over the last year that policy tightening started before you actually lifted off because the market anticipated your moves and tightened on your behalf. The market is now easing policy on your behalf by anticipating a funds rate by next September that's a full point below the current level, with cuts beginning around March. Is this something that you are broadly comfortable with?

CHAIR POWELL. So this last year has been remarkable for the, the sort of seesaw thing, the back-and-forth we've had over the course of the year of markets moving away and moving back and that kind of thing. So, and what I would just say is that we, we focus on what we have to do and how we need to use our tools to achieve our goals, and that's what we really focus on. And people are going to have different forecasts about the economy, and they're going to—those are going to show up in market conditions, or they won't, you know. But in any case, we have to do what we think is right.

And, you know, in the long run, it's important that financial conditions become aligned or are aligned with what we're trying to accomplish, and, in the long run, they will be, of course, because we will do what it takes to get to our goals. And, ultimately, that will mean that financial conditions will, will come along. But in the meantime, there can be back-and-forth, and, you know, I'm just focused on what's the right thing for us to do. And my colleagues are focused on that, too.

NICK TIMIRAOS. The markets seem to think inflation is coming down credibly. Do you believe we're at the point where inflation is coming down credibly?

CHAIR POWELL. Listen, I welcome the progress. I think it's, it's really good to see the progress that we're making. I think if you look at the 12-month—look at the 6-month measures, you see very low numbers. If you look at 12-month measures, you're still well above 2 percent. You're actually above 3 percent on core, through November, PCE [inflation]. That isn't to say—I'm not, you know, calling into question the progress. It's great. We just need to see more. We need to see, you know, continued further, further progress toward getting back to 2 percent. That's, that's what we need to see.

So, you know, our—it's our job to restore price stability. And that—it's one of our two jobs, along with maximum employment, and they're equal. So we're very focused on, on, you know, doing that. As I mentioned, we're moving carefully at this point. We're pleased with the progress, but, but we see the need for further progress, and I think—I think it's fair to say there is a lot of uncertainty about going forward. We've seen the economy move in surprising directions, so we're just going to need to see more further progress.

MICHELLE SMITH. Jeanna.

JEANNA SMIALEK. Jeanna Smialek, *New York Times.* Thanks for taking our questions. In the SEP from today, [real GDP] growth is notably below potential in 2024. If growth were to surprise us again in the way that it has for years now by being stronger than expected next year, would it still be possible to cut rates? Or, put another way, is below-trend growth necessary to cut rates, or would continued progress on inflation alone be sufficient?

CHAIR POWELL. So we'll, we'll look at the totality of the data. Growth is one thing, so is inflation, so is labor market data. So we'd, we'd look at the totality. As we—as we make decisions about policy changes going forward, we're going to be looking at all those things and, particularly, about the—as they affect the outlook. So it's ultimately all about the outlook and the balance of risks as well. So that's what—that's what we'd be looking for.

If we have stronger growth, you know, that'll be good for people. That'll be good for the labor market. It might actually mean that it takes a little longer to get inflation down to 2 percent. We will get it down to 2 percent, but, you know, if we see stronger growth, we'll—we will set policy according to what we actually see. And, and so that's how I would answer.

JEANNA SMIALEK. I guess the—I guess the question I'm asking, if you don't mind a quick follow-up, I guess the question I'm asking is, is above-trend growth itself a problem?

CHAIR POWELL. It's only a problem inso—it's not itself a problem. It's only a problem insofar as it makes it more difficult for us to achieve our goals. And, you know, if you have—if you have growth that's robust, what that will mean is probably it will keep the labor market very strong. It probably will, will place some upward pressure on inflation. That could mean that it takes longer to get to 2 percent inflation. That could mean we need to keep rates higher for longer. It could even mean, ultimately, that we would need to hike again. It just is—it's the way, the way our policy works.

MICHELLE SMITH. Let's go to Neil.

NEIL IRWIN. Hi, Chair Powell. Neil Irwin with Axios. How do you interpret the state of the labor market right now? And, in particular, you've referred even today to evidence that it's coming into better balance. What would you need to see to conclude that it has reached that balance?

CHAIR POWELL. So on, on the better-balance side, there are just a lot of things. It's—you see—you see job growth still strong but moving back down to more sustainable levels, given population growth and labor force participation. The things that are not quite—but let me go on with that list. You know, claims are low. If you look at surveys of businesses, they're, they're—sort of the era of this frantic labor shortage, [those kinds of worker shortages] are behind us, and they're seeing a shortage of labor as being significantly alleviated. If you look at shortages of workers, whereas they thought job, job availability was the highest that it'd ever been or close to it, that's now down to more normal levels by so many measures—participation, unemployment—so many measures: the unemployment—job openings, quits, all of those things.

So wages are still running a bit above what would be consistent with 2 percent inflation over a long period of time. They've been gradually cooling off. But if wages are running around 4 percent, that's still a bit above, I would say. And I guess there, there are just a couple of other—the unemployment rate is very, very low. And these are—but, but I would just say, overall, the development of the labor market has been very positive. It's been a good time for workers to find jobs and get solid wage increases.

MICHELLE SMITH. Claire.

CLAIRE JONES. Claire Jones, *Financial Times*. You know, I'd say the mood among economists at the moment seems to be one of cautious optimism, which is somewhat corroborated by your forecast by the sense that we are going to have a soft landing. Yet when we—when we hear from the general public, there's a lot of discord about economic conditions. What do you think explains this disconnect, and does it matter for policymakers?

CHAIR POWELL. It may be. A common theme is that, while inflation is coming down, and that's very good news, the price level is not coming down. Prices of some, some goods and services are coming down. But overall, in the aggregate, the price level is not. So people are still living with high prices, and that's, that's not—that is something that people don't like. And, you know, so what will happen with that is, wages are now—[changes in] real wages are now positive. So [nominal] wages are now moving up more than inflation, as inflation comes down. And so that might help improve the mood of people.

But we do see those—we see those public opinion surveys. The thing that we can do is to do our jobs, which is to use our tools to foster price stability, which has such great benefits over such long periods of time, and which is the thing that really enables us to work for and achieve an extended period of high employment, which is so beneficial for, you know, families and, and companies around the country.

MICHELLE SMITH. Victoria.

VICTORIA GUIDA. Hi. Victoria Guida with Politico. I wanted to ask, you know, on, on the flip side of if things start to deteriorate rapidly, if we do fall into a recession, if we do start to see unemployment rise, at sort of the levels of inflation that we're seeing now, how would you all think about that in terms of rate cuts? Would that be a sign that you've, you've done your job demand-wise?

CHAIR POWELL. Sorry—if?

VICTORIA GUIDA. If, if the economy starts to—looks like it's starting to fall into a recession; if, if the jobless rate starts to rise.

CHAIR POWELL. That's not something we're hoping to see. Obviously, we're hoping to, to see something very different—which is a continuation of what we have seen, which is the labor market coming into better balance without a significant increase in unemployment, inflation coming down without a significant increase in unemployment, and growth moderating without a significant increase in unemployment. That's what we're, we're trying very much to achieve and not something that we're looking to see.

VICTORIA GUIDA. But, but would you take that as a signal that you should cut rates?

CHAIR POWELL. You know, obviously, what we'll do is we'll look at the totality of the data, as I've mentioned a couple times, and, certainly, the labor data would be important in that. And, you know, if you—if you can describe a situation like that where if, if there were the beginning of a recession or something like that, then, yes, that would certainly weigh heavily on that decision.

MICHELLE SMITH. Michael McKee.

MICHAEL MCKEE. Michael McKee from Bloomberg Television and Radio. Mr. Chairman, you were, by your own admission, behind the curve in starting to raise rates to fight inflation, and you said earlier, again, "the full effects of our tightening (cycle) have not yet been felt." How will you decide when to cut rates, and how will you ensure you're not behind the curve there?

CHAIR POWELL. So we're, we're aware of the risk that we would hang on too long. You know, we know that that's a risk, and we're very focused on not making that mistake. And we do regard the two—you know, we've come back into a better balance between the risk of overdoing it and the risk of underdoing it. Not only that, we were able to focus hard on the—on the price-stability mandate. And we're getting back to the point where—which is what you do when you're very far from, from one of them, one of the two mandates—you're getting now back to the point where both mandates are important, and they're, they're more in balance, too. So I think we'll be—we'll be very much keeping that in mind, as we make policy going forward.

And the things we'll be looking at, I've already described. You know, we're, we're obviously looking hard at what's happening with demand, and what we see? We see the same thing other people see, which is a strong economy, which really put up quite a performance in 2023. We see good evidence and good reason to believe that growth will come in lower next year. And you see what the forecasts are. I think the median growth—median participant wrote down 1.4 percent growth, but, you know, we'll have to see. It's very hard to predict. We'll also be looking to see progress on inflation and, you know, the labor market remaining strong but, but ideally, without seeing the kind of large increase in unemployment that happens sometimes.

MICHAEL MCKEE. If I could follow up: When you begin the cutting cycle, will it be essentially run the same way you do it now with raising rates, where you basically do trial and error, cut and see what happens, or will you tie it to some particular measure of progress?

CHAIR POWELL. We haven't typically tried to articulate, with one exception, really specific target levels, which was if you—some of you will remember the thresholds that we used in, I guess, 2013. I don't—the answer is, these are things that we haven't, you know, really worked out yet. We're sort of just at the beginning of, of that discussion.

MICHELLE SMITH. Edward.

EDWARD LAWRENCE. Thank you, Mr. Chairman. Edward Lawrence of Fox Business. So if the Fed cuts rates as the dot plot is, is showing, about 75 basis points, does that signal that there's a belief of weakness next year in the economy?

CHAIR POWELL. It wouldn't, if that were to—first of all, let me just say, that isn't a plan. That's, that's just cumulating what people wrote down. So that's not something—you know this, but allow me to say it again: We don't debate or discuss what the right, you know, whose SEP is right. We just say what they are, and we tabulate them and publish them. So and it's, you know, it's important for people to know that. But it wouldn't need to be a sign of—it could just be a sign that the economy is normalizing, and it doesn't need the tight policy. It depends on—the economy can evolve in many different ways, right? So but, but it could be more of what I just described.

EDWARD LAWRENCE. And you focused on core inflation, we've heard from—in other meetings. How sticky is core inflation right now?

CHAIR POWELL. Well, that's what we're finding out, and we've, you know, we've seen real progress in, in core inflation. It has been sticky, and famously, the service sector is thought to be stickier, but we've actually seen reasonable progress in nonhousing services, which was the area where, where you would expect to see less progress. We are seeing some progress there, though. And, in fact, all three of the categories of core [prices] are now contributing: goods, housing services, nonhousing services. They're all contributing in different—at different levels, you know, meeting by meeting—or, rather, report by report. So, yeah.

MICHELLE SMITH. Okay. Let's go to Catarina.

CATARINA SARAIVA. Catarina Saraiva of Bloomberg News. Thanks for taking our questions. I just wanted to ask a little bit about, you know, we had some pretty positive data this, you know, this morning and yesterday. I'm assuming those were not incorporated into the forecast we see today, but I just wanted to ask, you know, how that kind of adds to your thinking, you know, on the inflation outlook.

CHAIR POWELL. Right. So we got—we got CPI the morning of the first day, and we got PPI the next day, which informs the, you know, the translation into PCE [inflation]. So it's very late in the game, you know, to—but nonetheless, participants are allowed to, encouraged to update their SEP forecast until probably midmorning today. After that, so staff has to—has to cumulate all of that and create the documents that you see. So until about midmorning, a little, maybe late morning, it's okay to update, and I believe some people did update their forecast based on what we saw today.

CATARINA SARAIVA. Okay. And do you see—I mean, how are you, when you think about, you know, starting to think about the rate cuts next year or whenever they come, how do you, you know, how do you think about the economy we're in now kind of post-pandemic? Do you think that there's been significant structural shifts, and is that going to change how you look at a rate cut path?

CHAIR POWELL. The question of whether there have been fundamental structural shifts is, is really hard to know the answer and a very interesting one right now. The one that would affect—the one that comes to mind, though, is just the question of where the neutral rate of interest is. And so, for example, if it's risen, and I'm not saying that it has, but if it were to have risen, that would mean that, that interest rates would need to be a little bit higher to convey the same level of restriction. The thing is, we're not really going to know that. You know, people will be writing papers about that 10 years from now and still fighting about it. So it's just that it's going to be uncertain.

So we're going to be making policy in this, you know, difficult, uncertain, really unprecedented environment. Some—someone once said that you know the—you know the natural rate of interest by its works, and that's really right, but that's very difficult because policy operates with a lag. So that's one of the reasons why we slowed down this year. We started slowing down at this meeting last year, reducing the pace at which we were adding restriction. And, over the course of this year, we really slowed down a lot to give those lags time to work.

In terms of demand, has demand shifted more away from services into goods? There's—you can make a case for that, that the shift back into services has not been complete, and it doesn't look like it's ongoing, but I don't know if that's right. Maybe people just bought so much stuff that they temporarily don't want any more stuff. They haven't got anyplace to put it. [Laughter]

MICHELLE SMITH. Let's go to Jennifer.

JENNIFER SCHONBERGER. Thank you, Chair Powell. Jennifer Schonberger with Yahoo Finance. You said back in July that you needed to start cutting rates before getting to 2 percent inflation. As you mentioned, PCE inflation is now running at 3½ on core. On a six-month annual basis, core PCE is running at 2½ percent, though when you look at supercore and shelter, they are, of course, stickier. So when looking in the different components of the data, how much closer do you have to get to 2 percent before you consider cutting rates?

CHAIR POWELL. I mean, the reason you wouldn't wait to get to 2 percent to cut rates is that policy would be, it would be too late. I mean, you'd want to be reducing restriction on the economy well before 2 percent because—or before you get to 2 percent so you don't overshoot, if we think, think of restrictive policy as weighing on economic activity. You know, it takes—it takes a while for policy to get into the economy, affect economic activity, and affect inflation. So I can't give you a precise answer. But if you look at what's in the—in the SEP, and, you know, I think you'll see a reasonable estimate of the time lags and things like that that it would take.

JENNIFER SCHONBERGER. Do think below 3 percent would be reasonable?

CHAIR POWELL. I wouldn't want to—I wouldn't want to identify any one precise point, because I would be able to look back then and probably find out that it turned out not to be right. But we'll be looking at it and, and looking at the broad collection of factors.

MICHELLE SMITH. Let's go to Jean Yung.

JEAN YUNG. Hi, Chair Powell. Jean Yung with Market News. I wanted to go back to the stickiness-of-inflation question. Over the past couple of years, a lot of central bankers have talked about the more difficult last mile of getting inflation back down to 2 percent, yet it's also been surprising how fast inflation has come down this year. I'm curious, do you think something has changed in our understanding of inflation, or do you subscribe to this notion still? Or is it something different about the U.S. economy? Thank you.

CHAIR POWELL. I think—I think this. You know, we felt since the beginning that it would be a combination of two factors. The first factor is just the unwinding of, of what happened in the pandemic: the distortions of supply and demand. And the second thing would be our policy, which was weighing on aggregate demand and actually making it easier for the supply side to recover because of lower demand. We thought those two things were going to be necessary. Sorry, say your—say the last part of your question again.

JEAN YUNG. If there was something different about the U.S. economy.

CHAIR POWELL. Yeah. So it's not that—it may or may not be about "different," the U.S. economy being different. I think that this inflation was not the classic demand overload, pot-boiling-over, kind of inflation that we [typically] think about. It was a combination of very strong demand, without question, and unusual supply-side restrictions, both on the goods side but also on the labor side, because we had a—we had a participation shock. So this is just very unusual.

And, you know, we had the view—my colleagues and I broadly had the view—that we could get a lot of—you know, you had essentially a vertical supply curve, because you ran into the limits of, of capacity at very low levels, because there weren't workers and because people couldn't—the supply chains were all broken. So we, we had the view that you could come straight down that vertical supply curve to the extent demand [was] lowered, reduced. And, you know, something like that has happened. It happened so far. The question is, you know, once, once that part of it runs out—and we think it has a ways to run; we definitely think that the sort of supply chain and shortages side has some, some ways to run—does labor force participation have much more to run? It might. Immigration could help, but it may be that, at some point—at some point, you will run out of supply-side help, and then it gets down to demand, and it gets harder. That's, that's very possible. But to say with certainty that the last mile is going to be different, I'd be reluctant to, you know, to suggest that we have any certainty around that. We just don't know. I mean, inflation keeps coming down. The labor market keeps getting back into balance. And it's so far, so good—although we kind of assume that it will get harder from here. But so far, it hasn't.

MICHELLE SMITH. Okay. We'll go to Megan for the last question.

MEGAN CASSELLA. Hi, Chair Powell. Thanks for taking our questions. Megan Cassella with *Barron's*. I want to ask about the balance sheet given the Fed's focus now on proceeding carefully and considering rate cuts. And can you talk us through what the latest thinking is, and has there been any consideration of altering the pace of quantitative tightening at all?

CHAIR POWELL. We're, we're not talking about altering the pace of QT right now, just to get that out of the way.

So the balance sheet seems to be working pretty much as expected. What we've been seeing is, you know, that we're allowing runoff each month. That's adding up. I think we're down—we're close to 1.2 trillion [dollars]. That's showing up. The reverse repo facility [take-up] has been coming down quickly, and reserves have been either moving up or—as a result—or holding steady. At a certain point, you know, there won't be any more to come out of, or there'll be a level where [take-up at] the reverse repo facility levels out. And, at that point, reserves will start to come down.

You know, we still have—you know that we intend to reduce our securities holdings until we judge that the quantity of reserve balances has reached a level somewhat above that consistent with ample reserves, and we also intend to slow and then stop the decline in size of the balance sheet when reserve balances are somewhat above the level judged to be consistent with ample reserves. We're not at those levels, you know, with, with reserves close to 3.5 trillion [dollars]. We're not—we don't think we're at those [levels judged consistent with ample] reserves. There isn't a lot of evidence of that. We're watching it carefully. And, you know, so far—so far, it's working pretty much as expected, we think.

MEGAN CASSELLA. Do you anticipate adjusting that thinking at all by the time you're, you're considering or moving forward with rate cuts? Is that time to rethink, or are you still going to follow that thinking?

CHAIR POWELL. So I think they're, they're on independent tracks. You're asking, though, the question, I guess you're implying the question of can you continue with QT at such time—QT, which is a tightening action—at such time as policy is still tight? And the answer is, it depends on the reason. You know, if you're—if you're—if you're cutting rates because you're going back to normal, that's one thing, [and distinct from] if you're cutting them because the economy is really weak. So you can imagine, you'd have to know what the reason is to know whether it would be appropriate to do those two things at the same time.

MICHELLE SMITH. Thank you.

CHAIR POWELL. Thanks very much.

Press Release

March 16, 2022

Implementation Note issued March 16, 2022

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on March 16, 2022:

- The Board of Governors of the Federal Reserve System voted unanimously to raise the interest rate paid on reserve balances to 0.4 percent, effective March 17, 2022.
- As part of its policy decision, the Federal Open Market Committee voted to authorize and direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

  "Effective March 17, 2022, the Federal Open Market Committee directs the Desk to:

  - Undertake open market operations as necessary to maintain the federal funds rate in a target range of 1/4 to 1/2 percent.
  - Conduct overnight repurchase agreement operations with a minimum bid rate of 0.5 percent and with an aggregate operation limit of $500 billion; the aggregate operation limit can be temporarily increased at the discretion of the Chair.
  - Conduct overnight reverse repurchase agreement operations at an offering rate of 0.3 percent and with a per-counterparty limit of $160 billion per day; the per-counterparty limit can be temporarily increased at the discretion of the Chair.
  - Roll over at auction all principal payments from the Federal Reserve's holdings of Treasury securities and reinvest all principal payments from the Federal Reserve's holdings of agency debt and agency mortgage-backed securities (MBS) in agency MBS.
  - Allow modest deviations from stated amounts for reinvestments, if needed for operational reasons.
  - Engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency MBS transactions."

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 1/4 percentage point increase in the primary credit rate to 0.5

percent, effective March 17, 2022. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Boston, Philadelphia, Cleveland, Richmond, Atlanta, Chicago, St. Louis, Minneapolis, Kansas City, and San Francisco.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website.

Last Update: March 16, 2022

Press Release

May 04, 2022

Implementation Note issued May 4, 2022

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on May 4, 2022:

- The Board of Governors of the Federal Reserve System voted unanimously to raise the interest rate paid on reserve balances to 0.9 percent, effective May 5, 2022.
- As part of its policy decision, the Federal Open Market Committee voted to authorize and direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

  "Effective May 5, 2022, the Federal Open Market Committee directs the Desk to:

  - Undertake open market operations as necessary to maintain the federal funds rate in a target range of 3/4 to 1 percent.
  - Conduct overnight repurchase agreement operations with a minimum bid rate of 1.0 percent and with an aggregate operation limit of $500 billion; the aggregate operation limit can be temporarily increased at the discretion of the Chair.
  - Conduct overnight reverse repurchase agreement operations at an offering rate of 0.8 percent and with a per-counterparty limit of $160 billion per day; the per-counterparty limit can be temporarily increased at the discretion of the Chair.
  - Roll over at auction the amount of principal payments from the Federal Reserve's holdings of Treasury securities maturing in the calendar month of June that exceeds a monthly cap of $30 billion. Redeem Treasury coupon securities up to this monthly cap and Treasury bills to the extent that coupon principal payments are less than the monthly cap.
  - Reinvest into agency mortgage-backed securities (MBS) the amount of principal payments from the Federal Reserve's holdings of agency debt and agency MBS received in the calendar month of June that exceeds a monthly cap of $17.5 billion.
  - Allow modest deviations from stated amounts for reinvestments, if needed for operational reasons.

    - Engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency MBS transactions."

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 1/2 percentage point increase in the primary credit rate to 1 percent, effective May 5, 2022. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Boston, New York, Philadelphia, Cleveland, Richmond, Atlanta, Chicago, St. Louis, Minneapolis, Kansas City, Dallas, and San Francisco.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

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Related Information

Statement Regarding Plans for Reducing SOMA Holdings of Treasury Securities, Agency Debt, and Agency Mortgage-Backed Securities

Last Update: May 04, 2022

Press Release

June 15, 2022

Implementation Note issued June 15, 2022

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on June 15, 2022:

- The Board of Governors of the Federal Reserve System voted unanimously to raise the interest rate paid on reserve balances to 1.65 percent, effective June 16, 2022.
- As part of its policy decision, the Federal Open Market Committee voted to authorize and direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

  "Effective June 16, 2022, the Federal Open Market Committee directs the Desk to:

  - Undertake open market operations as necessary to maintain the federal funds rate in a target range of 1-1/2 to 1-3/4 percent.
  - Conduct overnight repurchase agreement operations with a minimum bid rate of 1.75 percent and with an aggregate operation limit of $500 billion; the aggregate operation limit can be temporarily increased at the discretion of the Chair.
  - Conduct overnight reverse repurchase agreement operations at an offering rate of 1.55 percent and with a per-counterparty limit of $160 billion per day; the per-counterparty limit can be temporarily increased at the discretion of the Chair.
  - Roll over at auction the amount of principal payments from the Federal Reserve's holdings of Treasury securities maturing in the calendar months of June and July that exceeds a cap of $30 billion per month. Redeem Treasury coupon securities up to this monthly cap and Treasury bills to the extent that coupon principal payments are less than the monthly cap.
  - Reinvest into agency mortgage-backed securities (MBS) the amount of principal payments from the Federal Reserve's holdings of agency debt and agency MBS received in the calendar months of June and July that exceeds a cap of $17.5 billion per month.
  - Allow modest deviations from stated amounts for reinvestments, if needed for operational reasons.

  - Engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency MBS transactions."
- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 3/4 percentage point increase in the primary credit rate to 1.75 percent, effective June 16, 2022. In taking this action, the Board approved the request to establish that rate submitted by the Board of Directors of the Federal Reserve Bank of Minneapolis.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website .

Last Update: June 15, 2022

Press Release

September 21, 2022

Implementation Note issued September 21, 2022

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on September 21, 2022:

- The Board of Governors of the Federal Reserve System voted unanimously to raise the interest rate paid on reserve balances to 3.15 percent, effective September 22, 2022.
- As part of its policy decision, the Federal Open Market Committee voted to authorize and direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

  "Effective September 22, 2022, the Federal Open Market Committee directs the Desk to:

  - Undertake open market operations as necessary to maintain the federal funds rate in a target range of 3 to 3-1/4 percent.
  - Conduct overnight repurchase agreement operations with a minimum bid rate of 3.25 percent and with an aggregate operation limit of $500 billion; the aggregate operation limit can be temporarily increased at the discretion of the Chair.
  - Conduct overnight reverse repurchase agreement operations at an offering rate of 3.05 percent and with a per-counterparty limit of $160 billion per day; the per-counterparty limit can be temporarily increased at the discretion of the Chair.
  - Roll over at auction the amount of principal payments from the Federal Reserve's holdings of Treasury securities maturing in each calendar month that exceeds a cap of $60 billion per month. Redeem Treasury coupon securities up to this monthly cap and Treasury bills to the extent that coupon principal payments are less than the monthly cap.
  - Reinvest into agency mortgage-backed securities (MBS) the amount of principal payments from the Federal Reserve's holdings of agency debt and agency MBS received in each calendar month that exceeds a cap of $35 billion per month.
  - Allow modest deviations from stated amounts for reinvestments, if needed for operational reasons.

- Engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency MBS transactions."

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 3/4 percentage point increase in the primary credit rate to 3.25 percent, effective September 22, 2022. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Boston, Philadelphia, Cleveland, Richmond, Atlanta, Chicago, St. Louis, Kansas City, and Dallas.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website.

Last Update: September 21, 2022

Press Release

November 02, 2022

Implementation Note issued November 2, 2022

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on November 2, 2022:

- The Board of Governors of the Federal Reserve System voted unanimously to raise the interest rate paid on reserve balances to 3.9 percent, effective November 3, 2022.
- As part of its policy decision, the Federal Open Market Committee voted to authorize and direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

  "Effective November 3, 2022, the Federal Open Market Committee directs the Desk to:

  - Undertake open market operations as necessary to maintain the federal funds rate in a target range of 3-3/4 to 4 percent.
  - Conduct overnight repurchase agreement operations with a minimum bid rate of 4 percent and with an aggregate operation limit of $500 billion; the aggregate operation limit can be temporarily increased at the discretion of the Chair.
  - Conduct overnight reverse repurchase agreement operations at an offering rate of 3.8 percent and with a per-counterparty limit of $160 billion per day; the per-counterparty limit can be temporarily increased at the discretion of the Chair.
  - Roll over at auction the amount of principal payments from the Federal Reserve's holdings of Treasury securities maturing in each calendar month that exceeds a cap of $60 billion per month. Redeem Treasury coupon securities up to this monthly cap and Treasury bills to the extent that coupon principal payments are less than the monthly cap.
  - Reinvest into agency mortgage-backed securities (MBS) the amount of principal payments from the Federal Reserve's holdings of agency debt and agency MBS received in each calendar month that exceeds a cap of $35 billion per month.
  - Allow modest deviations from stated amounts for reinvestments, if needed for operational reasons.

    - Engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency MBS transactions."

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 3/4 percentage point increase in the primary credit rate to 4 percent, effective November 3, 2022. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Boston, Cleveland, Richmond, Atlanta, Chicago, St. Louis, Minneapolis, Dallas, and San Francisco.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website.

Last Update: November 02, 2022

Press Release

February 01, 2023

Implementation Note issued February 1, 2023

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on February 1, 2023:

- The Board of Governors of the Federal Reserve System voted unanimously to raise the interest rate paid on reserve balances to 4.65 percent, effective February 2, 2023.
- As part of its policy decision, the Federal Open Market Committee voted to authorize and direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

  "Effective February 2, 2023, the Federal Open Market Committee directs the Desk to:

  - Undertake open market operations as necessary to maintain the federal funds rate in a target range of 4-1/2 to 4-3/4 percent.
  - Conduct overnight repurchase agreement operations with a minimum bid rate of 4.75 percent and with an aggregate operation limit of $500 billion; the aggregate operation limit can be temporarily increased at the discretion of the Chair.
  - Conduct overnight reverse repurchase agreement operations at an offering rate of 4.55 percent and with a per-counterparty limit of $160 billion per day; the per-counterparty limit can be temporarily increased at the discretion of the Chair.
  - Roll over at auction the amount of principal payments from the Federal Reserve's holdings of Treasury securities maturing in each calendar month that exceeds a cap of $60 billion per month. Redeem Treasury coupon securities up to this monthly cap and Treasury bills to the extent that coupon principal payments are less than the monthly cap.
  - Reinvest into agency mortgage-backed securities (MBS) the amount of principal payments from the Federal Reserve's holdings of agency debt and agency MBS received in each calendar month that exceeds a cap of $35 billion per month.
  - Allow modest deviations from stated amounts for reinvestments, if needed for operational reasons.

  - Engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency MBS transactions."

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 1/4 percentage point increase in the primary credit rate to 4.75 percent, effective February 2, 2023. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Boston, New York, Philadelphia, Richmond, Atlanta, Chicago, Kansas City, Dallas, and San Francisco.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website .

Last Update: February 01, 2023

Press Release

March 22, 2023

Implementation Note issued March 22, 2023

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on March 22, 2023:

- The Board of Governors of the Federal Reserve System voted unanimously to raise the interest rate paid on reserve balances to 4.9 percent, effective March 23, 2023.
- As part of its policy decision, the Federal Open Market Committee voted to direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

  "Effective March 23, 2023, the Federal Open Market Committee directs the Desk to:

  - Undertake open market operations as necessary to maintain the federal funds rate in a target range of 4-3/4 to 5 percent.
  - Conduct standing overnight repurchase agreement operations with a minimum bid rate of 5 percent and with an aggregate operation limit of $500 billion.
  - Conduct standing overnight reverse repurchase agreement operations at an offering rate of 4.8 percent and with a per-counterparty limit of $160 billion per day.
  - Roll over at auction the amount of principal payments from the Federal Reserve's holdings of Treasury securities maturing in each calendar month that exceeds a cap of $60 billion per month. Redeem Treasury coupon securities up to this monthly cap and Treasury bills to the extent that coupon principal payments are less than the monthly cap.
  - Reinvest into agency mortgage-backed securities (MBS) the amount of principal payments from the Federal Reserve's holdings of agency debt and agency MBS received in each calendar month that exceeds a cap of $35 billion per month.
  - Allow modest deviations from stated amounts for reinvestments, if needed for operational reasons.
  - Engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency MBS transactions."

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 1/4 percentage point increase in the primary credit rate to 5 percent, effective March 23, 2023. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Boston, New York, Philadelphia, Richmond, Atlanta, Kansas City, Dallas, and San Francisco.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website .

Last Update: March 22, 2023

Press Release

May 03, 2023

Implementation Note issued May 3, 2023

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on May 3, 2023:

- The Board of Governors of the Federal Reserve System voted unanimously to raise the interest rate paid on reserve balances to 5.15 percent, effective May 4, 2023.
- As part of its policy decision, the Federal Open Market Committee voted to direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

  "Effective May 4, 2023, the Federal Open Market Committee directs the Desk to:

  - Undertake open market operations as necessary to maintain the federal funds rate in a target range of 5 to 5-1/4 percent.
  - Conduct standing overnight repurchase agreement operations with a minimum bid rate of 5.25 percent and with an aggregate operation limit of $500 billion.
  - Conduct standing overnight reverse repurchase agreement operations at an offering rate of 5.05 percent and with a per-counterparty limit of $160 billion per day.
  - Roll over at auction the amount of principal payments from the Federal Reserve's holdings of Treasury securities maturing in each calendar month that exceeds a cap of $60 billion per month. Redeem Treasury coupon securities up to this monthly cap and Treasury bills to the extent that coupon principal payments are less than the monthly cap.
  - Reinvest into agency mortgage-backed securities (MBS) the amount of principal payments from the Federal Reserve's holdings of agency debt and agency MBS received in each calendar month that exceeds a cap of $35 billion per month.
  - Allow modest deviations from stated amounts for reinvestments, if needed for operational reasons.
  - Engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency MBS transactions."

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 1/4 percentage point increase in the primary credit rate to 5.25 percent, effective May 4, 2023. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Boston, Philadelphia, Cleveland, Richmond, Atlanta, Chicago, St. Louis, Minneapolis, Kansas City, Dallas, and San Francisco.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website.

Last Update: May 03, 2023

Press Release

July 26, 2023

Implementation Note issued July 26, 2023

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on July 26, 2023:

- The Board of Governors of the Federal Reserve System voted unanimously to raise the interest rate paid on reserve balances to 5.4 percent, effective July 27, 2023.
- As part of its policy decision, the Federal Open Market Committee voted to direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

  "Effective July 27, 2023, the Federal Open Market Committee directs the Desk to:

  - Undertake open market operations as necessary to maintain the federal funds rate in a target range of 5-1/4 to 5-1/2 percent.
  - Conduct standing overnight repurchase agreement operations with a minimum bid rate of 5.5 percent and with an aggregate operation limit of $500 billion.
  - Conduct standing overnight reverse repurchase agreement operations at an offering rate of 5.3 percent and with a per-counterparty limit of $160 billion per day.
  - Roll over at auction the amount of principal payments from the Federal Reserve's holdings of Treasury securities maturing in each calendar month that exceeds a cap of $60 billion per month. Redeem Treasury coupon securities up to this monthly cap and Treasury bills to the extent that coupon principal payments are less than the monthly cap.
  - Reinvest into agency mortgage-backed securities (MBS) the amount of principal payments from the Federal Reserve's holdings of agency debt and agency MBS received in each calendar month that exceeds a cap of $35 billion per month.
  - Allow modest deviations from stated amounts for reinvestments, if needed for operational reasons.
  - Engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency MBS transactions."

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 1/4 percentage point increase in the primary credit rate to 5.5 percent, effective July 27, 2023. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Boston, Philadelphia, Cleveland, Richmond, Chicago, St. Louis. Minneapolis, Kansas City, Dallas, and San Francisco.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website .

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Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

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Interest Rates Have Peaked Amid Tight Financial Conditions

The Blue Chip Financial Forecasts (BCFF) see an economy that is likely to slow down in coming quarters due to tighter financial conditions. As a result of slowing growth and an accompanying decline in inflation, market yields are likely to continue to fall. The consensus expects that the Fed has completed its tightening cycle and will begin easing in 2024. The economy is expected to avoid a recession as it has shown resilience (especially in the labor market) in the face of policy tightening.

Slowdown ahead. The latest GDP figures for Q3 2023 showed a sizable 5.2% quarter-to-quarter annualized growth rate, but recent data suggest that demand is dwindling. The Atlanta Fed nowcast is currently pointing to a 2.1% pace in Q4. The BCFF consensus looks for an even slower growth rate of 1.2%. Importantly, the consensus expects tepid growth to persist for the entire forecast horizon. The average GDP growth forecast for all of 2024 is 0.7%, with particular weakness in the first three quarters.

In a special question, the median BCFF forecaster puts the odds of recession in the next 12 months at 45%. A significant minority of forecasters (27%) believes that a recession is the most likely path for the economy, and expects two or more consecutive quarterly declines in GDP. The other 73% of panelists expect a slowdown without recession.

Consistent with a soft economic outlook, the consensus projects continued declines in the inflation rate. The PCE inflation rate is expected to slide to 2.2% by midyear 2024, nearly a percentage point lower than the current inflation rate.

Tight financial conditions. Earlier this year, market interest rates had increased to levels not seen since before the 2008 financial crisis. For example, the 10-year Treasury yield nearly reached 5% in October. Rates rose for a variety of reasons including data showing economic resilience, which in turn signaled that the Fed might have to keep rates high for longer than anticipated. High rates have taken a toll on interest-sensitive sectors, such as housing and capital goods expenditures. There is a growing sense that elevated rates have done some of the work for the Fed in slowing the economy. In a special question, BCFF panelists overwhelmingly stated that the rise in rates has tightened financial conditions sufficiently to delay/prevent further interest rate increases.

Indeed, with the funds rate above 5%, inflation subsiding, and Fed asset holdings declining, policy does already seem quite tight. In a special question, panelists estimated that the neutral fed funds rate was 2.9%, which is well below the current funds rate target.

Falling market yields. As a result of tightening financial conditions and the drag on economic activity, the 10-year yield has actually begun to decline, falling by more than 60 basis points in the past month. This decline was aided by better-than-expected inflation news for October, with the CPI posting an unchanged reading for a 3.2% rise year to year. Core CPI rose 0.2% for a 4.0% rise year to year, the lowest reading since August 2021.

The BCFF consensus expectation that both economic growth and inflation will slow significantly in the near term is being reflected in projections for market rates. The slide in rates over the past month is expected to continue over the next six quarters. For example, consensus expectations for the 10-year Treasury yield are for a half-point drop to 4.3% by Q1 2025. At the same time, the 1-year Treasury bill rate is expected to fall by nearly 1.5 percentage points to 4.1%, suggesting a significant steepening of the yield curve and a move away from inversion.

Importantly, the BCFF consensus expects mortgage rates to fall by nearly 1 percentage point over the next six quarters, which could bring much needed relief to the beleaguered housing market. The weakness in the economy is also expected to affect corporate debt somewhat, as panelists look for the spread between corporates and Treasurys to widen slightly.

No more Fed tightening. Policymakers have made a point of leaving the door open to further hikes, even as Fed Chair Powell suggests that the economy may be resistant to higher rates. While supply chains have improved, aiding the decline in inflation, Powell has stated repeatedly that the path to lower inflation involves below-trend growth and softening in the labor market. Conversely, BCFF panelists believe that the Fed is finished hiking rates. In a special question, 100 percent of panelists indicated that the Fed had completed its tightening cycle. Markets agree – the federal funds futures market does not price in any further tightening either.

Funds rate cuts. Against this backdrop, every BCFF panelist expects the Fed to cut the fed funds rate in the forecast horizon. Three-quarters of the panelists believe the Fed will cut rates for the first time either in Q2 or Q3 2024. Respondents seem to be pushing out the timing of the first rate cut – two months ago no panelist thought rate cuts would start after Q3 2024, now 22% do. Still, the BCFF consensus is that the fed funds rate will drop to 4.2% by Q1 2025, with nearly all panelists indicating that Fed easing will be ongoing at that time.

Long-range forecasts. The Blue Chip semi-annual longer-range forecasts show BCFF panelists' views on trend growth, inflation, and interest rates out to 2034. From 2026 on, panelists expect US GDP growth will hover near 2%, which is slightly higher than the CBO estimate of the steady state. They anticipate inflation will subside toward the Fed's target through 2026 and remain there.

Interest rates are expected to fall but remain elevated relative to pre-pandemic norms. The BCFF consensus looks for the funds rate to drop to 3% by 2028 and remain there. Similarly, the 10-year yield is expected to decline to 3.9% in 2025 and stay there. For comparison, in the decade prior to the latest tightening cycle, the funds rate averaged 0.6% and the 10-year yield averaged 2%. The higher rate projections are consistent with panelists' judgments about the neutral fed funds rate, which is substantially higher than before the pandemic.

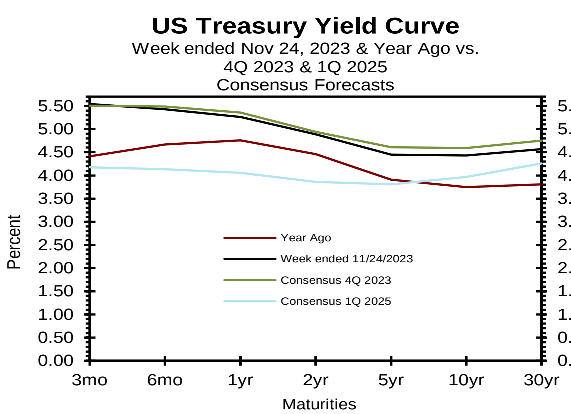
Peter D'Antonio (Haver Analytics, New York, NY)

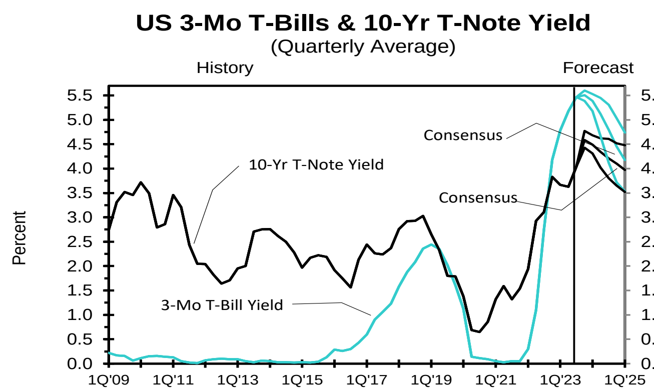
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

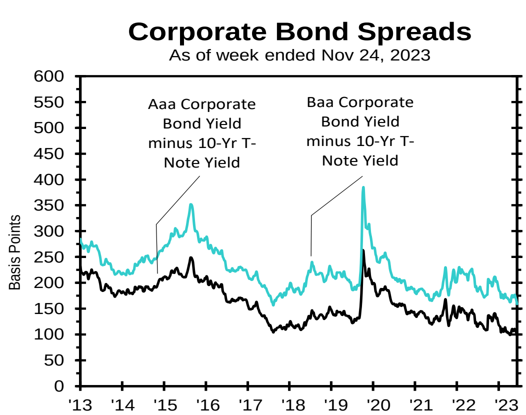
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	4Q	1Q	2Q	3Q	4Q	1Q
Interest Rates	Nov 24	Nov 17	Nov 10	Nov 3	Oct	Sep	Aug	3Q 2023	2023	2024	2024	2024	2024	2025
Federal Funds Rate	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.26	**5.4**	**5.4**	**5.2**	**4.9**	**4.6**	**4.2**
Prime Rate	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.43	**8.5**	**8.5**	**8.3**	**8.1**	**7.7**	**7.4**
SOFR	5.31	5.32	5.32	5.33	5.31	5.31	5.30	5.23	**5.4**	**5.3**	**5.2**	**4.9**	**4.6**	**4.3**
Commercial Paper, 1-mo.	5.33	5.34	5.32	5.33	5.33	5.31	5.30	5.26	**5.4**	**5.4**	**5.1**	**4.9**	**4.5**	**4.2**
Treasury bill, 3-mo.	5.54	5.52	5.54	5.57	5.60	5.56	5.56	5.54	**5.5**	**5.4**	**5.1**	**4.8**	**4.5**	**4.2**
Treasury bill, 6-mo.	5.43	5.41	5.46	5.51	5.57	5.51	5.54	5.53	**5.5**	**5.3**	**5.1**	**4.7**	**4.4**	**4.1**
Treasury bill, 1 yr.	5.26	5.27	5.35	5.38	5.42	5.44	5.37	5.39	**5.4**	**5.2**	**4.9**	**4.6**	**4.3**	**4.1**
Treasury note, 2 yr.	4.89	4.89	4.97	4.97	5.07	5.02	4.90	4.92	**4.9**	**4.8**	**4.5**	**4.2**	**4.0**	**3.9**
Treasury note, 5 yr.	4.45	4.50	4.59	4.69	4.77	4.49	4.31	4.31	**4.6**	**4.5**	**4.3**	**4.1**	**4.0**	**3.8**
Treasury note, 10 yr.	4.43	4.50	4.59	4.75	4.80	4.38	4.17	4.15	**4.6**	**4.5**	**4.3**	**4.2**	**4.1**	**4.0**
Treasury note, 30 yr.	4.57	4.65	4.75	4.93	4.95	4.47	4.28	4.24	**4.8**	**4.7**	**4.5**	**4.5**	**4.4**	**4.3**
Corporate Aaa bond	5.41	5.53	5.66	5.86	5.87	5.38	5.25	5.20	**5.5**	**5.5**	**5.3**	**5.3**	**5.1**	**5.0**
Corporate Baa bond	6.02	6.17	6.31	6.52	6.53	6.03	5.90	5.86	**6.4**	**6.4**	**6.4**	**6.3**	**6.2**	**6.1**
State & Local bonds	4.45	4.55	4.67	4.90	4.88	4.54	4.39	4.38	**4.6**	**4.7**	**4.6**	**4.6**	**4.5**	**4.4**
Home mortgage rate	7.29	7.44	7.50	7.76	7.62	7.20	7.07	7.04	**7.4**	**7.3**	**7.1**	**6.9**	**6.7**	**6.5**

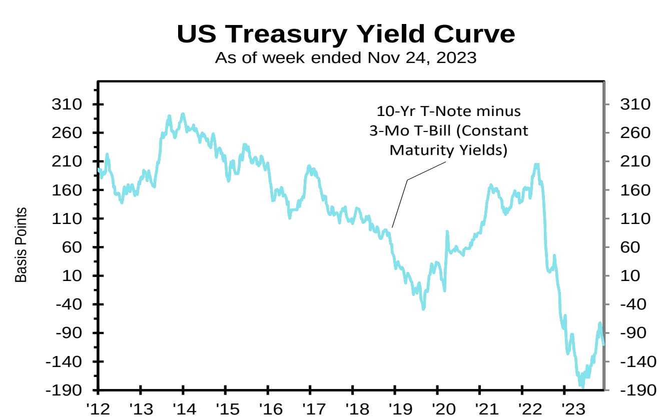
	History								Consensus Forecasts-Quarterly					
	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q
Key Assumptions	2021	2022	2022	2022	2022	2023	2023	2023	2023	2024	2024	2024	2024	2025
Fed's AFE $ Index	106.9	108.3	113.5	118.8	119.8	115.5	114.6	115.1	**116.6**	**116.3**	**115.9**	**115.9**	**115.7**	**115.7**
Real GDP	7.0	-2.0	-0.6	2.7	2.6	2.2	2.1	5.2	**1.2**	**0.7**	**0.3**	**0.6**	**1.2**	**1.7**
GDP Price Index	7.0	8.5	9.1	4.4	3.9	3.9	1.7	3.6	**2.7**	**2.4**	**2.3**	**2.2**	**2.2**	**2.2**
Consumer Price Index	8.8	9.2	9.7	5.5	4.2	3.8	2.7	3.6	**2.9**	**2.5**	**2.3**	**2.5**	**2.3**	**2.2**
PCE Price Index	6.8	7.7	7.2	4.7	4.1	4.2	2.5	2.8	**2.6**	**2.4**	**2.2**	**2.3**	**2.2**	**2.1**

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP, GDP Price Index and PCE Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index history is from the Department of Labor's Bureau of Labor Statistics (BLS).









Policy Rates[1]

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	5.38	5.38	3.88	**5.28**	**5.06**	**4.52**
Japan	-0.10	-0.10	-0.10	**-0.08**	**-0.06**	**0.01**
U.K.	5.25	5.25	3.00	**5.25**	**5.01**	**4.25**
Switzerland	1.75	1.75	0.50	**1.78**	**1.72**	**1.55**
Canada	5.00	5.00	3.75	**5.03**	**4.78**	**4.12**
Australia	4.35	4.10	2.85	**4.32**	**4.24**	**3.81**
Euro area	4.50	4.50	2.00	**4.39**	**4.11**	**3.61**

10-Yr. Government Bond Yields[2]

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	4.47	4.84	3.68	**4.54**	**4.33**	**4.03**
Germany	2.64	2.81	1.97	**2.60**	**2.50**	**2.32**
Japan	0.79	0.88	0.28	**0.88**	**0.86**	**0.90**
U.K.	4.34	4.61	3.26	**4.25**	**4.12**	**3.87**
France	3.20	3.45	2.44	**3.17**	**3.03**	**2.87**
Italy	4.39	4.84	3.85	**4.43**	**4.28**	**4.15**
Switzerland	0.98	1.09	1.01	**1.10**	**1.17**	**1.19**
Canada	3.72	3.98	2.94	**3.78**	**3.52**	**3.37**
Australia	4.55	4.81	3.58	**4.70**	**4.33**	**3.95**
Spain	3.58	3.98	2.82	**3.67**	**3.51**	**3.40**

Foreign Exchange Rates[3]

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	115.81	118.73	117.55	**115.9**	**114.9**	**113.6**
Japan	149.57	149.60	139.21	**148.1**	**145.4**	**139.8**
U.K.	1.26	1.22	1.21	**1.24**	**1.24**	**1.26**
Switzerland	0.88	0.90	0.95	**0.90**	**0.89**	**0.88**
Canada	1.36	1.39	1.34	**1.36**	**1.34**	**1.31**
Australia	0.66	0.64	0.68	**0.65**	**0.66**	**0.69**
Euro	1.09	1.06	1.04	**1.08**	**1.09**	**1.11**

Consensus Policy Rates vs. US Rate

	Now	In 12 Mo.
Japan	-5.48	**-4.51**
U.K.	-0.13	**-0.28**
Switzerland	-3.63	**-2.98**
Canada	-0.38	**-0.40**
Australia	-1.03	**-0.72**
Euro area	-0.88	**-0.92**

Consensus 10-Year Gov't Yields vs. U.S. Yield

	Now	In 12 Mo.
Germany	-1.83	**-1.71**
Japan	-3.68	**-3.13**
U.K.	-0.13	**-0.16**
France	-1.27	**-1.17**
Italy	-0.08	**0.12**
Switzerland	-3.49	**-2.85**
Canada	-0.75	**-0.66**
Australia	0.08	**-0.08**
Spain	-0.89	**-0.63**

Forecasts of panel members are on pages 10 and 11. Definitions of variables are as follows: [1]Monetary policy rates. [2]Government bonds are yields to maturity. [3]Foreign exchange rate forecasts for U.K., Australia and the Euro are U.S. dollars per currency unit. For the U.S dollar, forecasts are of the U.S. Federal Reserve Board's AFE Dollar Index.

International. Growing conviction that central banks have concluded their tightening cycles has fueled a rally in both bond and equity markets over the past few weeks. That conviction has been bolstered by a number of factors. First, global inflationary pressures have continued to diminish, in large part because of weaker energy prices. And, notwithstanding the recent instability in the Middle East, oil prices have continued to decline over the past two months, which has further eased concerns that this trend toward weaker inflation might stall. Second, there is growing evidence to suggest that higher interest rates are taking a heavier toll on global economic activity, evidence that's particularly compelling in the euro area and the UK. Lastly, the latest policy decisions and accompanying statements from various central banks - including the Fed, the ECB, and the BoE - indicate a growing consensus among policymakers that further tightening may not be necessary.

This month's survey of Blue Chip Financial Forecasters aligns with that narrative. The policy rate projections for the US, Canada, Europe, and Australia, for example, indicate a broadly shared consensus that tightening cycles have reached their conclusion. And that corresponds too with the responses to a special question, where approximately 90% of panelists believe the ECB and BoE have completed their tightening cycles with that proportion rising to 100% for the Fed.

Closer scrutiny of these policy rate projections further reveals that easing cycles are now expected to commence in the euro area, Switzerland, Australia, the UK as well as the US within the next 6 months. Financial futures contracts, moreover, indicate that investors believe that easing campaigns could potentially begin even earlier. Those views do not, however, chime with the messages from central banks in recent weeks. Even the more dovish members of most central banks' policy committees have staunchly opposed these views over the last few weeks.

That dichotomy of views could reflect a more downbeat view from our panelists about the outlook for growth and inflation next year compared with the expectations of central banks. In response to another special question, for example, 55% of our panelists expect a euro area recession over the next 12 months while 58% expect a UK recession. As noted above, moreover, downbeat views about the growth outlook – and euro area growth in particular - have been validated of late by much of the incoming data. The flash PMI surveys for November, for example, reveal ongoing contractions in the manufacturing sector in the euro area, UK, Japan and the US.

Still, those recession odds for Europe and downbeat data points for manufacturing have not been amplified elsewhere. For example, only 44% of our panelists now anticipate a US recession phase over the next 12 months, down a little from 47% in our last survey. Those same flash PMI surveys for November, in the meantime, suggest that activity has held up quite well in the service sector in the US, UK and Japan.

Against this backdrop, investors are likely to be alert to how this dichotomy of views is resolved. Will the incoming data for both growth and inflation disappoint to the downside and thereby validate the consensus view that easing cycles will shortly commence? Alternatively, will growth and hold up and thereby challenge the dovish Blue Chip consensus but at the same time validate the more hawkish central bank consensus?

However, the outlook for the world economy and financial markets will not solely hinge on these considerations. Economic developments in Asia will also be closely watched. In response to another special question, 74% of our panelists believe the situation in China poses significant risks to global growth. Moreover, Japan's economic outlook could wield considerable influence over global financial stability as well. There is ample speculation in particular about if and when the BoJ will start to normalize its monetary policy. In a final special question this month, for example, 62% of our panelists expect that an interest rate normalization campaign could begin before the middle of 2024.

Fourth Quarter 2023

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term				Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)			
	1 Federal Funds Rate	2 Prime Bank Rate	3 SOFR Rate	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
Scotiabank Group	5.5 H	na	5.3 L	na	5.5	na	na	5.2 H	5.0 H	5.0 H	5.1 H	na	na	na	na	na	0.2 L	1.5 L	4.7 H	4.7 H
TS Lombard	5.5 H	8.6 H	5.4	5.5	5.4	5.5	5.1 L	4.7 L	4.3	4.4	4.5	5.2	6.1	4.4	6.2 L	115.0	1.5	3.6 H	3.6	3.6
Bank of America	5.4	na	na	na	na	na	na	4.9	4.7	4.5	4.8	na	na	na	na	na	1.5	2.7	2.6	2.5
BMO Capital Markets	5.4	8.5	5.3 L	5.4	5.6 H	5.5	5.3	4.9	4.6	4.6	4.7	5.5	6.6	5.1	7.5	117.8	0.9	2.2	2.8	2.3
Chan Economics	5.4	8.4 L	5.3 L	5.3 L	5.4	5.5	5.3	4.8	4.3	4.4	4.6	5.6	6.6	5.0	7.2	115.0	1.5	2.7	2.9	2.6
Comerica Bank	5.4	8.6 H	5.4	na	5.4	5.5	5.3	4.9	4.7	4.7	4.9	5.6	6.6	na	7.7	na	0.7	2.4	2.4	2.4
Daiwa Capital Markets America	5.4	8.5	na	na	5.3 L	na	na	4.9	4.5	4.5	4.7	na	na	na	7.3	117.0	1.0	2.6	3.0	3.3
Fannie Mae	5.4	8.5	na	na	5.5	5.5	5.3	4.9	4.5	4.5	4.7	na	na	na	7.3	na	1.1	2.9	2.4	2.4
Georgia State University	5.4	8.5	na	na	5.5	5.4	5.5	5.0	4.7	4.6	4.8	5.5	6.6	na	7.6	na	1.1	2.6	2.8	2.6
GLC Financial Economics	5.4	8.5	5.4	5.4	5.5	5.4	5.3	4.8	4.5	4.4	4.6	5.2	6.0 L	4.2	6.8	117.1	0.7	3.6 H	2.4	2.0
Goldman Sachs & Co.	5.4	na	na	na	5.6 H	na	na	5.0	4.7	4.8	4.4	na	na	na	na	na	1.9	1.8	2.6	2.1
ING	5.4	na	na	na	na	na	na	4.8	4.5	4.5	4.6	na	na	na	na	na	1.9	na	na	na
J.P. Morgan Chase	5.4	na	na	na	na	na	na	4.7 L	4.2 L	4.1 L	4.3 L	na	na	na	na	na	2.0 H	3.0	2.9	2.4
KPMG	5.4	8.5	5.4	5.4	5.6 H	5.6	5.5	5.1	4.7	4.7	4.8	5.6	6.7	na	7.6	na	1.1	2.9	2.8	2.6
MacroPolicy Perspectives	5.4	8.5	5.3 L	5.4	5.6 H	5.5	5.4	5.0	4.7	4.5	4.8	5.1 L	6.0 L	4.5	7.3	116.1	1.5	2.5	3.1	2.1
Nomura Securities, Inc.	5.4	8.5	na	na	na	na	na	4.9	4.6	4.6	na	na	na	na	na	na	0.9	1.9	2.8	2.4
Oxford Economics	5.4	8.5	5.4	na	5.6 H	5.6	5.4	5.1	4.7	4.7	4.9	5.3	na	na	7.6	118.8 H	1.0	2.7	4.3	3.3
RDQ Economics	5.4	8.5	5.4	5.8 H	5.5	5.5	5.2	4.9	4.7	4.6	4.7	5.5	6.3	4.7	7.4	116.9	1.5	3.2	3.0	2.8
S&P Global Market Intelligence	5.4	8.5	5.4	na	5.5	5.4	5.5	5.1	4.7	4.7	4.9	na	na	na	7.6	na	1.1	2.9	2.8	2.6
The Lonski Group	5.4	8.5	5.3 L	5.4	5.5	5.5	5.2	4.9	4.6	4.6	4.7	5.6	6.3	4.6	7.4	117.0	1.1	2.6	2.9	3.5
The Northern Trust Company	5.4	8.5	5.3 L	5.4	5.6 H	5.5	5.4	5.0	4.6	4.6	4.8	5.4	6.4	4.7	7.5	117.5	0.8	2.3	3.2	2.9
Wells Fargo	5.4	8.5	5.4	5.4	5.4	5.4	5.2	4.8	4.5	4.5	4.7	5.7	6.7	5.1	7.5	na	0.7	2.7	3.4	2.7
Action Economics	5.3 L	8.5	5.7 H	5.4	5.5	5.5	5.4	5.0	4.8	4.9	5.0	5.7	6.7	4.5	8.0 H	115.1	1.6	2.2	2.2	1.4 L
Barclays	5.3 L	na	na	na	5.4	na	na	na	na	na	na	na	na	na	na	na	1.5	2.8	2.9	2.7
Chmura Economics & Analytics	5.3 L	8.5	5.3 L	5.4	5.6 H	5.5	5.4	5.0	4.6	4.6	4.8	5.4	na	na	7.5	na	1.7	3.3	3.3	3.1
DePrince & Assoc.	5.3 L	8.5	5.4	5.4	5.6 H	5.5	5.4	5.0	4.6	4.6	4.8	5.4	6.4	4.3	7.5	116.7	1.1	3.0	3.3	3.1
Economist Intelligence Unit	5.3 L	8.5	na	5.4	5.6 H	5.5	5.3	5.1	4.7	4.5	4.8	na	na	na	7.5	na	0.6	na	2.9	na
EY-Parthenon	5.3 L	na	na	na	5.4	na	na	na	na	4.6	na	na	na	na	na	na	1.3	2.7	2.5	2.1
Loomis, Sayles & Company	5.3 L	8.5	5.3 L	5.3 L	5.5	5.5	5.3	5.0	4.6	4.5	4.7	5.3	6.3	4.6	7.4	117.2	1.1	2.9	2.9	2.6
MacroFin Analytics & Rutgers Bus School	5.3 L	8.5	5.3 L	5.4	5.5	5.4	5.4	4.9	4.4	4.5	4.6	5.5	6.0 L	4.5	7.4	115.8	1.2	3.3	3.3	2.7
Moody's Analytics	5.3 L	8.5	5.3 L	5.4	5.3 L	5.3 L	5.3	5.1	4.8	4.7	5.0	5.8	6.8 H	4.4	7.7	na	0.8	2.7	3.2	3.1
NatWest Markets	5.3 L	na	na	5.4	5.6 H	5.7 H	5.8 H	4.8	4.5	4.5	4.8	5.8	6.7	5.2 H	7.0	na	1.0	2.2	2.5	2.2
PNC Financial Services Corp.	5.3 L	8.5	5.3 L	na	5.4	5.5	5.4	5.0	4.7	4.6	4.8	na	6.5	4.1	7.5	114.6 L	1.4	2.7	2.4	2.1
Regions Financial Corporation	5.3 L	8.5	5.3 L	5.4	5.5	5.5	5.3	4.9	4.6	4.6	4.7	5.6	6.4	4.7	7.4	117.3	0.6	2.7	2.9	2.7
Santander Capital Markets	5.3 L	8.5	5.3 L	5.4	5.6 H	5.5	5.3	4.9	4.6	4.6	4.8	5.4	6.4	3.9 L	7.5	116.8	1.9	3.0	2.6	2.5
Societe Generale	5.3 L	8.5	5.3 L	na	5.5	5.5	5.3	4.9	4.6	4.6	4.7	na	na	na	na	na	1.6	2.7	2.7	2.0
Via Nova Investment Mgt.	5.3 L	8.5	5.3 L	5.3 L	5.6 H	5.5	5.5	5.1	4.8	4.9	5.0	6.0 H	6.6	4.9	7.7	117.6	2.0 H	2.2	2.1 L	2.0
December Consensus	**5.4**	**8.5**	**5.4**	**5.4**	**5.5**	**5.5**	**5.4**	**4.9**	**4.6**	**4.6**	**4.8**	**5.5**	**6.4**	**4.6**	**7.4**	**116.6**	**1.2**	**2.7**	**2.9**	**2.6**
Top 10 Avg.	5.4	8.5	5.4	5.5	5.6	5.5	5.5	5.1	4.8	4.8	4.9	5.7	6.7	4.9	7.7	117.4	1.8	3.2	3.5	3.3
Bottom 10 Avg.	5.3	8.5	5.3	5.4	5.4	5.4	5.3	4.8	4.4	4.4	4.6	5.3	6.2	4.3	7.1	115.9	0.7	2.1	2.4	2.0
November Consensus	5.4	8.5	5.4	5.4	5.5	5.5	5.4	5.0	4.7	4.7	4.8	5.6	6.6	4.8	7.5	117.6	0.9	2.7	3.2	2.9
Number of Forecasts Changed From A Month Ago:																				
Down	8	4	4	4	13	16	12	18	20	20	17	13	12	14	17	11	9	15	21	19
Same	29	24	21	16	16	8	13	12	8	6	7	3	4	5	2	4	9	5	5	8
Up	0	1	0	1	4	4	3	5	7	10	10	7	6	0	9	3	19	15	10	8
Diffusion Index	39%	45%	42%	43%	36%	29%	34%	31%	31%	36%	40%	37%	36%	13%	36%	28%	64%	50%	35%	34%

First Quarter 2024

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 SOFR Rate	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For ---Qtr.--- A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
S&P Global Market Intelligence	5.6 H	8.7 H	5.6	na	5.6 H	5.5	5.6	5.1 H	4.7	4.6	4.8	na	na	na	7.5	na	0.9	2.4	1.9	1.9
J.P. Morgan Chase	5.5	na	na	na	na	na	na	4.8	4.4	4.4	4.6	na	na	na	na	na	1.3	1.9	2.1	1.7
Scotiabank Group	5.5	na	5.3	na	5.4	na	na	4.4	4.2	4.5	4.6	na	na	na	na	na	0.0	1.6 L	2.3	2.6
Bank of America	5.4	na	na	na	na	na	na	4.8	4.5	4.4	4.7	na	na	na	na	na	0.5	3.1	3.2	3.1
BMO Capital Markets	5.4	8.5	5.3	5.4	5.5	5.4	5.1	4.6	4.4	4.4	4.6	5.4	6.5	5.0	7.4	117.2	0.2	2.7	3.2	3.0
Chan Economics	5.4	8.4	5.3	5.3	5.4	5.5	5.3	4.8	4.3	4.4	4.6	5.6	6.6	5.0	7.2	114.7	1.0	2.6	2.8	2.4
Chmura Economics & Analytics	5.4	8.5	5.4	5.4	5.5	5.5	5.4	4.9	4.6	4.6	4.7	5.4	na	na	7.6	na	0.3	3.0	3.0	2.9
Comerica Bank	5.4	8.6	5.4	na	5.4	5.4	5.1	4.5	4.4	4.5	4.7	5.4	6.3	na	7.3	na	0.5	2.2	2.4	2.5
Daiwa Capital Markets America	5.4	8.5	na	na	5.3	na	na	4.5	4.1 L	4.3	4.4 L	na	na	na	7.1	116.0	-1.0 L	2.6	2.6	2.5
DePrince & Assoc.	5.4	8.5	5.4	5.4	5.5	5.4	5.3	4.9	4.6	4.6	4.7	5.5	6.5	4.6	7.3	117.2	0.7	2.7	2.9	2.7
GLC Financial Economics	5.4	8.5	5.4	5.3	5.4	5.2	5.0	4.5	4.7	4.6	4.7	5.4	6.2	4.4	6.7	116.9	1.3	3.5 H	2.8	2.4
Goldman Sachs & Co.	5.4	na	na	na	5.5	na	na	5.0	4.7	4.8 H	4.7	na	na	na	na	na	1.8	2.3	2.7	2.4
ING	5.4	na	na	na	na	na	na	4.5	4.2	4.3	4.5	na	na	na	na	na	0.0	na	na	na
KPMG	5.4	8.5	5.4	5.3	5.5	5.6	5.5	5.0	4.7	4.6	4.7	5.5	6.6	na	7.5	na	0.8	2.4	1.9	1.9
MacroPolicy Perspectives	5.4	8.5	5.3	na	na	na	na	4.7	4.3	4.5	na	na	na	na	7.2	na	1.2	2.0	1.8	1.6
Nomura Securities, Inc.	5.4	8.5	na	na	na	na	na	4.8	4.5	4.5	na	na	na	na	na	na	1.3	1.6 L	2.5	2.2
Oxford Economics	5.4	8.5	5.4	na	5.6 H	5.5	5.4	5.0	4.6	4.6	4.8	5.3	na	na	7.5	119.4 H	0.0	2.6	2.9	2.5
RDQ Economics	5.4	8.5	5.4	6.0 H	5.3	5.2	4.9	4.7	4.6	4.6	4.6	5.8	6.6	4.7	7.3	117.3	0.5	3.0	3.4 H	3.2 H
The Northern Trust Company	5.4	8.5	5.3	5.4	5.5	5.4	5.4	5.0	4.8	4.7	5.0 H	5.6	6.6	4.9	7.6	116.0	0.9	2.3	2.8	2.6
Wells Fargo	5.4	8.5	5.4	5.4	5.2	5.1	4.7	4.4	4.2	4.3	4.6	5.5	6.5	4.9	7.2	na	0.9	2.5	2.9	2.5
Action Economics	5.3	8.5	5.8 H	5.4	5.5	5.4	5.3	4.9	4.7	4.7	4.8	5.6	6.6	4.5	7.8 H	118.4	0.6	1.8	1.9	1.4 L
Barclays	5.3	na	na	na	5.4	na	na	5.0	4.7	4.8 H	5.0 H	na	na	na	na	na	1.0	3.1	2.9	3.0
Economist Intelligence Unit	5.3	8.5	na	5.4	5.5	5.4	5.1	5.0	4.7	4.6	4.8	na	na	na	7.5	na	-0.9	na	2.3	na
EY-Parthenon	5.3	na	na	na	5.0	na	na	na	na	4.2 L	na	na	na	na	na	na	-0.1	2.5	2.5	2.2
Fannie Mae	5.3	8.4	na	na	5.3	5.3	5.0	4.7	4.3	4.4	4.5	na	na	na	7.0	na	0.1	2.2	1.8	1.8
Georgia State University	5.3	8.4	na	na	5.4	5.2	5.2	4.8	4.5	4.5	4.7	5.4	6.6	na	7.4	na	0.3	2.3	1.9	1.9
Loomis, Sayles & Company	5.3	8.5	5.3	5.3	5.5	5.5	5.3	5.0	4.6	4.5	4.7	5.3	6.3	4.6	7.3	116.8	1.5	2.1	1.7 L	1.6
MacroFin Analytics & Rutgers Bus School	5.3	8.5	5.3	5.4	5.3	5.4	5.4	4.8	4.4	4.4	4.5	5.4	5.9 L	4.4	7.2	115.7	1.0	2.5	2.8	2.6
Moody's Analytics	5.3	8.5	5.3	5.3	5.1	5.1	5.0	4.8	4.5	4.3	4.7	5.7	6.7	4.4	7.1	na	1.1	2.1	2.7	2.4
NatWest Markets	5.3	na	na	5.4	5.6 H	5.7 H	5.8 H	4.5	4.3	4.4	4.7	5.7	6.6	5.1	6.9	na	1.3	1.6 L	2.2	1.9
PNC Financial Services Corp.	5.3	8.5	5.3	na	5.3	5.4	5.2	4.9	4.7	4.5	4.6	na	6.9 H	5.3 H	7.4	115.0	0.4	2.2	1.8	1.8
Regions Financial Corporation	5.3	8.5	5.3	5.4	5.5	5.4	5.2	4.8	4.4	4.4	4.6	5.3	6.3	4.6	7.2	116.5	0.4	2.4	2.8	2.9
Santander Capital Markets	5.3	8.5	5.3	5.4	5.5	5.4	5.2	4.9	4.5	4.6	4.8	5.4	6.4	4.0 L	7.4	116.0	1.2	3.1	2.8	2.6
Societe Generale	5.3	8.5	5.3	na	5.3	5.1	4.7	4.2 L	4.3	4.3	4.5	na	na	na	na	na	0.5	1.8	2.2	2.2
The Lonski Group	5.3	8.5	5.3	5.4	5.5	5.3	5.0	4.8	4.5	4.3	4.5	5.4	6.1	4.5	7.2	117.9	0.4	2.2	2.3	2.6
Via Nova Investment Mgt.	5.3	8.5	5.4	5.4	5.3	5.3	5.3	4.9	4.9 H	4.8 H	4.9	5.9 H	6.5	4.8	7.6	116.0	2.5 H	2.1	2.1	2.1
TS Lombard	4.8 L	7.9 L	4.8 L	4.8 L	4.7 L	4.8 L	4.5 L	4.3	4.2	4.3	4.4 L	5.1 L	6.0	4.3	6.1 L	110.0 L	0.2	3.2	3.2	3.2 H
December Consensus	**5.4**	**8.5**	**5.3**	**5.4**	**5.4**	**5.3**	**5.2**	**4.8**	**4.5**	**4.5**	**4.7**	**5.5**	**6.4**	**4.7**	**7.3**	**116.3**	**0.7**	**2.4**	**2.5**	**2.4**
Top 10 Avg.	5.4	8.5	5.5	5.5	5.5	5.5	5.4	5.0	4.7	4.7	4.8	5.6	6.6	4.9	7.5	117.4	1.5	3.0	3.0	2.9
Bottom 10 Avg.	5.3	8.4	5.3	5.3	5.2	5.2	4.9	4.4	4.2	4.3	4.5	5.3	6.3	4.4	7.0	115.3	-0.1	1.9	1.9	1.8
November Consensus	5.4	8.5	5.4	5.4	5.4	5.4	5.2	4.8	4.5	4.5	4.7	5.5	6.5	4.8	7.3	118.0	0.3	2.4	2.5	2.4
Number of Forecasts Changed From A Month Ago:																				
Down	10	7	7	6	12	10	10	14	12	14	12	12	11	13	13	11	10	14	11	12
Same	25	19	17	9	13	11	13	15	13	10	11	3	3	2	6	3	12	9	8	11
Up	2	3	1	5	7	6	4	7	11	13	11	7	7	3	9	3	15	12	17	12
Diffusion Index	39%	43%	38%	48%	42%	43%	39%	40%	49%	49%	49%	39%	40%	22%	43%	26%	57%	47%	58%	50%

Second Quarter 2024

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	1 Federal Funds Rate	2 Prime Bank Rate	3 SOFR Rate	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)			
S&P Global Market Intelligence	5.6 H	8.7 H	5.5	na	5.4	5.2	5.2	4.8	4.4	4.4	4.6	na	na	na	7.2	na	0.1	2.9	2.8	2.6
J.P. Morgan Chase	5.5	na	na	na	na	na	na	4.6	4.3	4.4	4.7	na	na	na	na	na	0.5	2.0	1.9	1.5
Action Economics	5.4	8.5	5.8 H	5.4	5.5	5.3	5.1	4.8	4.6	4.6	4.7	5.4	6.4	4.4	7.7 H	118.7	1.0	1.9	2.3	1.7
BMO Capital Markets	5.4	8.5	5.3	5.4	5.5	5.4	5.0	4.3	4.3	4.3	4.5	5.4	6.5	5.0	7.3	117.2	0.8	2.2	2.4	2.3
Chan Economics	5.4	8.4	5.3	5.3	5.4	5.5 H	5.3 H	4.8	4.3	4.4	4.6	5.6	6.6	5.0	7.2	114.8	0.5	2.6	2.8	2.4
Goldman Sachs & Co.	5.4	na	na	na	5.3	na	na	4.9	4.6	4.7	4.7	na	na	na	na	na	1.6	2.2	2.3	2.3
Nomura Securities, Inc.	5.4	8.5	na	na	na	na	na	4.6	4.4	4.5	na	na	na	na	na	na	1.4	1.5	2.2	1.9
Oxford Economics	5.4	8.5	5.4	na	5.6 H	5.5 H	5.3 H	5.0 H	4.4	4.4	4.7	5.2	na	na	7.3	119.0 H	0.0	2.2	2.3	2.2
RDQ Economics	5.4	8.5	5.4	5.9 H	5.3	5.2	4.8	4.5	4.5	4.5	4.5	5.9 H	7.0	4.7	7.1	116.4	-1.1	3.1	3.4 H	3.2 H
The Northern Trust Company	5.4	8.5	5.3	5.5	5.4	5.4	5.3 H	4.7	4.7 H	4.7	5.0 H	5.7	6.8	5.0	7.5	115.0	1.1	2.2	2.5	2.4
Barclays	5.3	na	na	na	5.4	na	na	4.9	4.6	4.7	4.9	na	na	na	na	na	0.0	2.4	1.8	2.2
Chmura Economics & Analytics	5.3	8.4	5.3	5.3	5.3	5.4	5.3 H	4.9	4.6	4.8 H	4.8	5.5	na	na	7.7 H	na	0.5	3.1	2.9	2.6
Comerica Bank	5.3	8.5	5.3	na	5.3	5.2	4.8	4.1	4.1	4.2	4.5	5.2	6.1	na	6.8	na	1.0	2.1	2.0	2.2
Economist Intelligence Unit	5.3	8.5	na	5.3	5.3	5.2	4.9	4.8	4.5	4.5	4.6	na	na	na	7.3	na	0.5	na	2.3	na
EY-Parthenon	5.3	na	na	na	4.9	na	na	na	na	4.0	na	na	na	na	na	na	0.8	2.3	2.0	2.1
KPMG	5.3	8.5	5.3	5.1	5.3	5.3	5.1	4.7	4.3	4.3	4.4	5.1	6.3	na	7.1	na	0.5	2.9	2.7	2.6
Loomis, Sayles & Company	5.3	8.5	5.3	5.3	5.5	5.5 H	5.3 H	5.0 H	4.6	4.5	4.7	5.3	6.3	4.6	7.2	116.8	1.1	2.5	2.1	1.9
Moody's Analytics	5.3	8.5	5.3	5.2	5.0	4.9	4.8	4.7	4.4	4.2	4.7	5.6	6.7	4.3	6.8	na	1.2	2.0	2.6	2.5
PNC Financial Services Corp.	5.3	8.5	5.3	na	5.3	5.2	5.1	4.8	4.7 H	4.6	4.7	na	7.1 H	5.9 H	7.3	117.2	-0.8	2.1	1.7	1.7
Regions Financial Corporation	5.3	8.5	5.3	5.3	5.4	5.4	5.1	4.5	4.3	4.2	4.4	5.2	6.2	4.5	7.0	116.1	1.0	2.7	3.1	3.0
Santander Capital Markets	5.3	8.5	5.3	5.4	5.4	5.3	5.1	4.9	4.5	4.5	4.7	5.4	6.5	3.9 L	7.2	115.5	1.1	2.9	2.9	2.6
Scotiabank Group	5.3	na	5.1	na	5.0	na	na	3.9	3.9	4.2	4.3	na	na	na	na	na	0.2	0.8 L	1.7	1.5
DePrince & Assoc.	5.2	8.3	5.3	5.2	5.3	5.3	5.2	4.9	4.6	4.6	4.7	5.6	6.6	4.8	7.1	117.6	1.0	2.6	2.8	2.6
MacroFin Analytics & Rutgers Bus School	5.2	8.4	5.1	5.3	5.2	5.3	5.1	4.8	4.2	4.4	4.5	5.2	5.8	4.3	7.1	115.5	1.0	2.3	2.5	2.5
MacroPolicy Perspectives	5.2	8.4	5.1	na	na	na	na	4.5	4.3	4.5	na	na	na	na	7.1	na	1.5	1.8	1.5	1.4
Bank of America	5.1	na	na	na	na	na	na	4.5	4.4	4.3	4.7	na	na	na	na	na	0.5	2.6	2.8	2.5
Daiwa Capital Markets America	5.1	8.3	na	na	4.9	na	na	4.1	3.7 L	3.9	4.2	na	na	na	6.6	116.0	-1.4	2.5	2.5	2.4
Fannie Mae	5.1	8.3	na	na	5.1	5.0	4.8	4.5	4.3	4.3	4.5	na	na	na	6.9	na	-1.5	2.6	2.0	2.1
GLC Financial Economics	5.1	8.2	5.1	5.0	5.0	4.8	4.7	4.2	4.3	4.3	4.5	5.1	6.1	4.3	6.4	113.3	1.2	2.9	2.6	2.2
Societe Generale	5.1	8.3	5.1	na	4.9	4.6	4.1	3.5 L	3.7 L	3.8 L	4.1 L	na	na	na	na	na	-1.8	1.8	2.2	2.0
Wells Fargo	5.1	8.3	5.1	5.1	4.8	4.4	3.9	3.7	3.7 L	3.9	4.2	5.1	6.1	4.5	6.7	na	-0.3	1.3	1.0 L	1.3 L
Via Nova Investment Mgt.	5.0	8.3	5.1	5.1	5.0	5.0	5.0	4.6	4.6	4.5	4.6	5.6	6.2	4.5	7.3	114.0	2.5 H	2.1	2.1	2.1
ING	4.9	na	na	na	na	na	na	4.1	4.0	4.0	4.4	na	na	na	na	na	-2.0 L	na	na	na
The Lonski Group	4.9	8.1	4.9	4.9	4.7	4.7	4.5	4.4	4.2	4.0	4.1 L	5.1	6.0	4.2	6.9	118.5	0.0	2.3	2.2	2.3
Georgia State University	4.5	7.6	na	na	4.5	4.2	4.1	3.9	4.0	4.3	4.4	5.2	6.3	na	7.2	na	-0.5	2.8	2.7	2.6
NatWest Markets	4.3	na	na	4.4	4.6	4.7	4.8	3.6	3.8	4.3	4.7	5.2	6.1	4.9	6.7	na	-1.5	1.8	1.1	1.8
TS Lombard	3.5 L	6.6 L	3.5 L	3.5 L	3.4 L	3.5 L	3.6 L	3.8	3.9	4.0	4.1 L	4.9 L	5.7 L	4.0	5.8 L	108.0 L	0.4	3.2 H	3.2	3.2 H
December Consensus	**5.2**	**8.3**	**5.2**	**5.1**	**5.1**	**5.1**	**4.9**	**4.5**	**4.3**	**4.3**	**4.5**	**5.3**	**6.4**	**4.6**	**7.1**	**115.9**	**0.3**	**2.3**	**2.3**	**2.2**
Top 10 Avg.	5.4	8.5	5.4	5.4	5.5	5.4	5.2	4.9	4.6	4.6	4.8	5.6	6.7	4.9	7.4	117.4	1.4	2.9	2.9	2.8
Bottom 10 Avg.	4.8	8.0	4.9	4.9	4.7	4.6	4.4	3.9	3.9	4.0	4.3	5.1	6.1	4.3	6.7	114.5	-1.1	1.7	1.7	1.7
November Consensus	5.2	8.4	5.3	5.2	5.2	5.1	4.9	4.5	4.3	4.3	4.5	5.4	6.4	4.6	7.1	117.2	0.3	2.3	2.4	2.2
Number of Forecasts Changed From A Month Ago:																				
Down	12	7	8	8	13	11	12	14	14	11	12	10	10	9	12	11	13	5	10	6
Same	21	17	14	9	14	9	10	14	13	13	11	7	6	7	6	3	12	14	13	18
Up	4	5	3	3	5	7	5	8	9	13	11	5	5	2	10	3	12	16	13	11
Diffusion Index	39%	47%	40%	38%	38%	43%	37%	42%	43%	53%	49%	39%	38%	31%	46%	26%	49%	66%	54%	57%

Third Quarter 2024

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 SOFR Rate	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For ---Qtr.--- A. Fed's Adv Fgn Econ $ Index	(Q-Q % Change) (SAAR) B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
Chan Economics	5.4 H	8.4	5.3	5.3	5.4	5.5 H	5.3 H	4.8	4.3	4.4	4.6	5.6	6.6	5.0	7.2	114.5	0.3	2.4	2.6	2.2
Goldman Sachs & Co.	5.4 H	na	na	na	5.0	na	na	4.8	4.6	4.6	4.6	na	na	na	na	na	1.7	2.3	2.4	2.3
J.P. Morgan Chase	5.4 H	na	na	na	na	na	na	4.3	4.1	4.2	4.6	na	na	na	na	na	0.5	2.5	2.7	2.3
Oxford Economics	5.4 H	8.5 H	5.4	na	5.5 H	5.4	5.2	4.8	4.0	4.3	4.6	4.6 L	na	na	7.1	117.7	0.5	2.3	2.2	2.2
Action Economics	5.3	8.4	5.8 H	5.3	5.3	5.1	4.9	4.7	4.5	4.5	4.7	5.4	6.4	4.3	7.6	118.8	1.3	1.4 L	2.4	1.7
Barclays	5.3	na	na	na	5.3	na	na	4.6	4.4	4.5	4.7	na	na	na	na	na	-0.5	2.8	2.6	2.6
BMO Capital Markets	5.3	8.4	5.3	5.3	5.5 H	5.4	4.9	4.1	4.1	4.2	4.4	5.4	6.5	5.0	7.2	117.4	1.3	2.2	2.4	2.2
Loomis, Sayles & Company	5.3	8.5 H	5.3	5.3	5.5 H	5.5 H	5.3 H	5.0	4.6	4.5	4.7	5.3	6.3	4.6	7.1	116.7	-1.5	1.9	1.2 L	1.2 L
Regions Financial Corporation	5.3	8.5 H	5.3	5.2	5.2	5.1	4.9	4.3	4.2	4.1	4.4	5.2	6.2	4.5	6.8	115.7	1.2	2.4	2.4	2.6
S&P Global Market Intelligence	5.3	8.4	5.3	na	5.1	4.8	4.8	4.4	4.1	4.2	4.4	na	na	na	6.8	na	1.1	2.5	3.3	2.7
Santander Capital Markets	5.3	8.5 H	5.3	5.3	5.2	5.1	4.9	4.7	4.4	4.3	4.7	5.5	6.6	3.8 L	6.9	115.0	0.8	2.7	2.7	2.3
PNC Financial Services Corp.	5.2	8.3	5.2	na	5.0	5.0	4.9	4.7	4.7	4.7	4.8	na	7.1	5.9 H	7.3	119.7 H	-1.4	2.0	1.6	1.6
RDQ Economics	5.2	8.3	5.2	5.7 H	5.1	5.0	4.6	4.3	4.4	4.4	4.4	6.0	7.2 H	4.6	6.9	116.2	-1.8 L	3.0	3.2	3.1
Comerica Bank	5.1	8.3	5.1	na	5.1	4.9	4.5	3.9	3.9	4.0	4.3	5.0	5.9	na	6.5	na	1.3	2.0	2.1	2.2
Economist Intelligence Unit	5.1	8.3	na	5.1	5.0	4.8	4.6	4.6	4.4	4.4	4.5	na	na	na	7.1	na	1.1	na	2.2	na
Fannie Mae	5.1	8.3	na	na	4.9	4.8	4.6	4.4	4.2	4.3	4.5	na	na	na	6.7	na	-0.5	2.2	2.1	2.0
Nomura Securities, Inc.	5.1	8.3	na	na	na	na	na	3.7	3.7	3.9	na	na	na	na	na	na	-1.1	2.0	2.8	2.5
The Northern Trust Company	5.1	8.3	5.1	5.2	5.1	4.9	4.7	4.3	4.4	4.5	4.8	5.6	6.7	4.8	7.0	114.0	1.3	2.2	2.3	2.3
Chmura Economics & Analytics	5.0	8.1	4.9	5.0	5.0	5.1	5.2	4.8	4.5	4.7	4.8	5.4	na	na	7.4	na	0.8	2.8	2.8	2.5
DePrince & Assoc.	5.0	8.1	5.0	5.0	5.0	5.0	4.9	4.7	4.6	4.6	4.7	5.7	6.6	4.8	7.0	117.3	1.8	2.5	2.7	2.5
EY-Parthenon	5.0	na	na	na	4.6	na	na	na	na	3.9	na	na	na	na	na	na	1.5	2.2	2.5	2.2
Moody's Analytics	5.0	8.2	5.0	4.9	4.7	4.7	4.6	4.5	4.3	4.1	4.6	5.6	6.6	4.3	6.7	na	1.5	1.8	2.3	2.3
Bank of America	4.9	na	na	na	na	na	na	4.3	4.3	4.3	4.7	na	na	na	na	na	0.5	2.7	2.5	2.4
KPMG	4.9	8.0	4.9	4.6	4.9	4.8	4.7	4.3	3.9	3.9	4.1	4.8	6.0	na	6.5	na	1.0	2.6	3.4 H	2.8
Scotiabank Group	4.8	na	4.6	na	4.2	na	na	3.7	3.8	4.0	4.2	na	na	na	na	na	0.8	1.5	3.2	1.9
Via Nova Investment Mgt.	4.8	8.0	4.8	4.9	4.8	4.8	4.8	5.1 H	5.1 H	5.1 H	5.1 H	6.2 H	6.8	5.1	7.9 H	112.0	2.5 H	2.1	2.1	2.1
GLC Financial Economics	4.7	7.8	4.6	4.7	4.6	4.6	4.4	4.0	4.2	4.2	4.5	5.1	6.0	4.3	6.2	116.1	2.1	1.4 L	2.2	2.3
MacroPolicy Perspectives	4.7	7.8	4.6	na	na	na	na	4.0	4.2	4.3	na	na	na	na	6.8	na	2.0	2.4	2.5	2.0
Daiwa Capital Markets America	4.6	7.8	na	na	4.4	na	na	3.7	3.5 L	3.6	4.3	na	na	na	6.3	115.0	1.0	2.4	2.5	2.4
MacroFin Analytics & Rutgers Bus School	4.6	7.8	4.5	4.7	4.5	4.7	4.8	4.7	4.0	4.2	4.4	5.1	5.7 L	4.1	6.9	115.3	1.3	2.2	2.3	2.4
Societe Generale	4.6	7.8	4.6	na	4.4	4.1	3.7	3.3	3.5 L	3.6	3.9 L	na	na	na	na	na	-0.5	1.8	2.2	1.9
ING	4.4	na	na	na	na	na	na	3.5	3.5 L	3.5 L	3.9 L	na	na	na	na	na	-1.7	na	na	na
The Lonski Group	4.4	7.6	4.4	4.4	4.2	4.2	4.1	4.0	4.0	3.9	4.1	5.0	5.8	4.1	6.7	118.7	0.8	2.1	2.1	2.2
Wells Fargo	4.4	7.5	4.4	4.4	4.0	3.6	3.4 L	3.4	3.5 L	3.7	4.0	4.9	5.9	4.3	6.4	na	-1.5	1.4 L	1.3	1.4
Georgia State University	4.0	7.2	na	na	3.9	3.7	3.5	3.5	3.7	4.0	4.3	5.0	6.1	na	6.8	na	0.4	2.4	3.3	2.6
TS Lombard	3.5	6.6 L	3.5 L	3.5	3.4 L	3.5 L	3.6	3.8	3.9	4.0	4.1	4.9	5.7 L	4.0	5.8 L	110.0 L	1.5	3.4 H	3.4 H	3.4 H
NatWest Markets	3.3 L	na	na	3.4 L	3.6	3.7	3.8	3.2 L	3.5 L	4.1	4.6	4.9	5.8	4.6	6.4	na	-0.5	1.6	1.7	2.0
December Consensus	**4.9**	**8.1**	**4.9**	**4.9**	**4.8**	**4.7**	**4.6**	**4.2**	**4.1**	**4.2**	**4.5**	**5.3**	**6.3**	**4.6**	**6.9**	**115.9**	**0.6**	**2.2**	**2.5**	**2.3**
Top 10 Avg.	5.3	8.4	5.3	5.3	5.3	5.2	5.0	4.8	4.6	4.6	4.8	5.6	6.7	4.9	7.3	117.4	1.7	2.8	3.1	2.7
Bottom 10 Avg.	4.3	7.6	4.5	4.5	4.1	4.2	4.0	3.6	3.7	3.8	4.1	4.9	5.9	4.2	6.4	114.4	-1.1	1.7	1.9	1.8
November Consensus	4.9	8.0	4.9	4.8	4.8	4.7	4.6	4.2	4.1	4.2	4.5	5.2	6.3	4.5	6.8	116.6	1.0	2.2	2.5	2.3
Number of Forecasts Changed From A Month Ago:																				
Down	11	7	7	7	14	14	12	12	11	10	12	8	8	10	13	8	17	10	8	8
Same	22	16	15	9	12	8	7	13	16	15	10	7	7	4	6	5	12	16	16	15
Up	4	6	3	4	6	5	8	11	9	12	12	7	6	4	9	4	8	9	12	12
Diffusion Index	41%	48%	42%	43%	38%	33%	43%	49%	47%	53%	50%	48%	45%	33%	43%	38%	38%	49%	56%	56%

Fourth Quarter 2024

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For Qtr.	(Q-Q % Change) (SAAR)			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.	E.
	Federal Funds Rate	Prime Bank Rate	SOFR Rate	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Adv Fgn Econ $ Index	Real GDP	GDP Price Index	Cons. Price Index	PCE Price Index
Barclays	5.3 H	na	na	na	5.1	na	na	4.4	4.3	4.3	4.5	na	na	na	na	na	1.0	2.7	2.6	2.6
Chan Economics	5.2	8.2	5.1	5.1	5.2	5.3 H	5.1 H	4.6	4.1	4.2	4.4	5.4	6.4	4.8	7.0	114.3	0.8	2.3	2.5	2.1
Goldman Sachs & Co.	5.1	na	na	na	4.8	na	na	4.6	4.5	4.6	4.5	na	na	na	na	na	1.9	2.1	2.4	2.1
Loomis, Sayles & Company	5.1	8.3 H	5.1	5.1	5.2	5.1	4.9	4.6	4.6	4.5	4.7	5.3	6.3	4.6	6.9	116.6	-2.2 L	1.9	1.5 L	1.5 L
Regions Financial Corporation	5.1	8.3 H	5.1	5.2 H	4.8	4.8	4.8	4.1	4.1	4.1	4.3	5.1	6.2	4.4	6.7	115.5	1.6	2.4	2.4	2.5
S&P Global Market Intelligence	5.1	8.2	5.0	na	4.8	4.5	4.5	4.1	3.9	4.0	4.3	na	na	na	6.5	na	1.3	2.3	2.0	2.1
Santander Capital Markets	5.1	8.3 H	5.1	5.1	4.7	4.6	4.5	4.4	4.2	4.1	4.4	5.2	6.3	3.6 L	6.6	114.0	1.1	2.5	2.5	2.1
Action Economics	5.0	8.2	5.7 H	5.0	5.1	4.9	4.6	4.6	4.5	4.5	4.6	5.3	6.3	4.3	7.6 H	119.0	1.6	1.5	2.4	1.8
BMO Capital Markets	5.0	8.2	5.0	5.1	5.2	5.1	4.6	3.9	4.0	4.1	4.3	5.3	6.4	4.8	7.1	117.6	1.5	2.0	2.2	2.0
Fannie Mae	5.0	8.1	na	na	4.6	4.6	4.4	4.3	4.2	4.3	4.4	na	na	na	6.6	na	0.5	2.2	2.6	2.3
J.P. Morgan Chase	5.0	na	na	na	na	na	na	3.9	3.9	4.0	4.5	na	na	na	na	na	0.8	2.3	2.4	2.0
Oxford Economics	5.0	8.2	5.0	na	5.3 H	5.2	4.9	4.5	3.7	4.1	4.4	4.2 L	na	na	6.9	116.1	0.7	2.3	1.8	2.2
PNC Financial Services Corp.	5.0	8.1	5.0	na	4.7	4.6	4.6	4.6	4.7	4.8 H	5.0	na	7.1 H	5.9 H	7.2	122.0 H	-1.2	1.9	1.8	1.6
Comerica Bank	4.8	8.0	4.8	na	4.7	4.5	4.0	3.5	3.5	3.7	4.0	4.7	5.6 L	na	6.0	na	1.5	2.0	2.1	2.2
Economist Intelligence Unit	4.8	8.0	na	4.8	4.8	4.6	4.5	4.4	4.2	4.3	4.5	na	na	na	7.0	na	1.5	na	2.1	na
EY-Parthenon	4.8	na	na	na	4.4	na	na	na	na	3.8	na	na	na	na	na	na	1.8	2.1	2.2	2.1
Moody's Analytics	4.8	7.9	4.7	4.7	4.5	4.4	4.4	4.3	4.2	4.1	4.5	5.5	6.5	4.2	6.5	na	1.5	1.9	2.2	2.3
DePrince & Assoc.	4.7	7.8	4.7	4.7	4.7	4.7	4.6	4.5	4.5	4.5	4.6	5.7	6.6	4.9	6.8	117.1	2.1	2.4	2.6	2.4
RDQ Economics	4.7	7.8	4.7	5.1	4.6	4.6	4.4	4.2	4.3	4.3	5.3 H	5.9 H	7.0	5.6	6.8	115.1	0.9	2.9	3.0	3.0
Bank of America	4.6	na	na	na	na	na	na	4.0	4.2	4.3	4.8	na	na	na	na	na	1.0	2.5	1.9	2.2
Nomura Securities, Inc.	4.6	7.8	na	na	na	na	na	3.2	3.3 L	3.7	na	na	na	na	na	na	-1.9	1.6	2.7	2.3
The Northern Trust Company	4.6	7.8	4.6	4.7	4.5	4.3	4.2	3.9	4.2	4.3	4.6	5.6	6.7	4.7	6.8	112.0	1.5	2.1	2.2	2.2
Chmura Economics & Analytics	4.5	7.7	4.5	4.6	4.6	4.8	4.8	4.6	4.4	4.6	4.8	5.4	na	na	7.0	na	1.9	2.5	2.6	2.4
KPMG	4.5	7.6	4.5	4.1	4.4	4.4	4.2	3.9	3.5	3.6	3.9	4.5	5.7	na	6.0	na	2.0	2.4	2.1	2.2
Via Nova Investment Mgt.	4.5	7.8	4.6	4.6	4.5	4.5	4.5	4.8 H	4.8 H	4.8 H	4.8	5.9 H	6.6	4.8	7.6 H	110.0 L	2.5	2.1	2.0	2.1
GLC Financial Economics	4.3	7.4	4.3	4.3	4.3	4.2	4.1	3.7	4.1	4.1	4.4	4.9	5.9	4.3	6.0	115.9	1.6	1.6	2.0	2.2
MacroPolicy Perspectives	4.2	7.4	4.2	na	na	na	na	3.5	4.0	4.3	na	na	na	na	6.5	na	2.3	2.5	2.7	2.1
Societe Generale	4.2	7.3	4.2	na	3.9	3.6	3.3	3.1 L	3.5	3.6	3.9	na	na	na	na	na	3.7 H	1.8	2.2	1.8
Daiwa Capital Markets America	4.1	7.3	na	na	4.0	na	na	3.4	3.3 L	3.5 L	4.2	na	na	na	6.1	115.0	2.0	2.3	2.4	2.3
MacroFin Analytics & Rutgers Bus School	4.1	7.3	4.0	4.3	3.9	4.2	4.4	4.5	3.8	4.0	4.4	5.0	5.6 L	3.9	6.7	115.1	1.6	2.2	2.1	2.2
Scotiabank Group	4.0	na	3.8	na	3.7	na	na	3.5	3.6	4.0	4.2	na	na	na	na	na	1.2	1.1 L	2.9	2.9
ING	3.9	na	na	na	na	na	na	3.3	3.4	3.5 L	3.9	na	na	na	na	na	1.0	na	na	na
The Lonski Group	3.9	7.1	3.9	4.0	3.7	3.8	3.7	3.7	3.8	3.9	4.0	5.0	5.8	4.1	6.6	119.3	1.5	2.2	2.1	2.0
Georgia State University	3.6	6.8	na	na	3.5	3.2 L	3.1 L	3.4	3.4	3.7	4.0	4.7	5.9	na	6.6	na	0.8	2.2	2.0	2.0
Wells Fargo	3.6	6.8	3.6	3.6	3.4 L	3.3	3.2	3.2	3.3 L	3.5 L	3.8 L	4.7	5.7	4.1	6.1	na	0.3	2.6	3.1	2.6
TS Lombard	3.5	6.6 L	3.5 L	3.5	3.4 L	3.5	3.6	3.8	3.9	4.0	4.1	4.9	5.7	4.0	5.8 L	112.0	2.0	3.2 H	3.2 H	3.2 H
NatWest Markets	3.1 L	na	na	3.2 L	3.4 L	3.5	3.6	3.1 L	3.4	4.0	4.6	4.8	5.7	4.5	6.3	na	1.5	1.4	2.7	2.4
December Consensus	**4.6**	**7.7**	**4.6**	**4.5**	**4.5**	**4.4**	**4.3**	**4.0**	**4.0**	**4.1**	**4.4**	**5.1**	**6.2**	**4.5**	**6.7**	**115.7**	**1.2**	**2.2**	**2.3**	**2.2**
Top 10 Avg.	5.1	8.2	5.1	5.0	5.0	4.9	4.7	4.6	4.5	4.5	4.8	5.5	6.6	4.9	7.1	117.4	2.2	2.6	2.8	2.6
Bottom 10 Avg.	3.8	7.2	4.1	4.1	3.7	3.8	3.7	3.3	3.4	3.7	4.0	4.7	5.8	4.1	6.2	113.9	-0.1	1.7	1.9	1.9
November Consensus	4.5	7.6	4.5	4.4	4.5	4.4	4.3	3.9	3.9	4.0	4.3	5.1	6.2	4.4	6.6	116.4	1.5	2.2	2.5	2.3
Number of Forecasts Changed From A Month Ago:																				
Down	9	5	5	4	15	15	12	9	8	6	9	8	8	8	10	8	14	10	11	8
Same	20	17	14	11	12	8	11	14	15	16	11	8	7	5	8	4	17	16	18	16
Up	8	7	6	5	5	4	4	11	11	13	12	6	6	5	10	5	6	9	7	11
Diffusion Index	49%	53%	52%	53%	34%	30%	35%	53%	54%	60%	55%	45%	45%	42%	50%	41%	39%	49%	44%	54%

First Quarter 2025

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For Qtr.	(Q-Q % Change) (SAAR)			
	1 Federal Funds Rate	2 Prime Bank Rate	3 SOFR Rate	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Adv Fgn Econ $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index	E. PCE Price Index
Barclays	5.1 H	na	na	na	4.9	na	na	na	na	na	na	na	na	na	na	na	1.0	3.0 H	3.1 H	2.8 H
Chan Economics	4.9	7.9	4.8	4.8 H	4.9	5.0 H	4.8 H	4.3	3.8	3.9	4.1	5.1	6.1	4.5	6.7	114.0	1.5	2.2	2.4	2.0
Goldman Sachs & Co.	4.9	na	na	na	4.6	na	na	4.5	4.4	4.5	4.5	na	na	na	na	na	1.9	2.2	2.5	2.2
Action Economics	4.8	7.9	5.4 H	4.8 H	4.8	4.6	4.4	4.4	4.4	4.4	4.6	5.3	6.3	4.2	7.5	119.2	1.6	1.8	2.4	1.8
BMO Capital Markets	4.8	7.9	4.8	4.8 H	5.0 H	4.9	4.4	3.8	3.9	4.1	4.2	5.2	6.3	4.8	7.1	117.8	1.7	2.1	2.3	2.1
Oxford Economics	4.8	8.0 H	4.8	na	5.0 H	4.9	4.7	4.4	3.4	3.9	3.8	4.0 L	na	na	6.7	114.3	1.2	2.3	2.1	2.1
Fannie Mae	4.7	7.8	na	na	4.4	4.4	4.3	4.2	4.2	4.3	4.4	na	na	na	6.4	na	1.2	2.1	2.8	2.3
PNC Financial Services Corp.	4.7	7.8	4.7	na	4.4	4.2	4.3	4.5	4.7	4.9 H	5.2 H	na	7.1 H	6.0 H	7.2	123.4 H	0.4 L	2.1	2.0	1.8
S&P Global Market Intelligence	4.7	7.8	4.6	na	4.4	4.1	4.1	3.8	3.6	3.8	4.1	na	na	na	6.1	na	1.5	2.1	0.8 L	1.5
Economist Intelligence Unit	4.6	7.8	na	4.6	4.6	4.4	4.3	4.3	4.1	4.0	4.4	na	na	na	6.7	na	1.9	na	2.2	na
Loomis, Sayles & Company	4.6	7.8	4.6	4.6	4.7	4.6	4.4	4.0	4.4	4.5	4.7	5.3	6.3	4.6	6.8	116.5	1.0	2.1	2.0	2.0
Regions Financial Corporation	4.6	7.8	4.5	4.7	4.5	4.6	4.7	3.8	3.9	4.0	4.3	5.1	6.1	4.3	6.5	115.1	1.7	2.2	2.2	2.3
Santander Capital Markets	4.6	7.8	4.6	4.6	4.2	4.1	4.0	4.0	3.8	3.8	4.1	4.9	6.0	3.4 L	6.2	113.0	1.3	2.8	2.4	2.1
Moody's Analytics	4.5	7.7	4.5	4.4	4.3	4.2	4.3	4.2	4.1	4.0	4.5	5.5	6.5	4.2	6.4	na	1.6	2.2	2.2	2.3
Bank of America	4.4	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	1.5	2.6	2.4	2.5
Comerica Bank	4.4	7.6	4.4	na	4.2	4.1	3.6	3.1	3.3	3.5	3.9	4.7	5.5 L	na	5.8 L	na	1.5	1.9	2.0	2.0
J.P. Morgan Chase	4.4	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.0	2.3	2.5	2.1
DePrince & Assoc.	4.3	7.5	4.4	4.4	4.4	4.4	4.3	4.3	4.4	4.5	4.6	5.7	6.6	4.8	6.7	116.9	2.4	2.3	2.6	2.4
EY-Parthenon	4.3	na	na	na	3.9	na	na	na	na	3.7	na	na	na	na	na	na	2.3	2.2	2.1	2.1
Via Nova Investment Mgt.	4.3	7.5	4.3	4.4	4.2	4.3	4.4	4.7 H	4.9 H	4.9 H	5.0	6.0 H	6.6	4.9	7.7 H	110.0 L	2.5	2.2	2.0	2.1
Chmura Economics & Analytics	4.2	7.3	4.2	4.2	4.3	4.4	4.4	4.6	4.4	4.6	4.8	5.3	na	na	6.7	na	2.5	2.4	2.5	2.4
GLC Financial Economics	4.2	7.3	4.3	4.2	4.2	4.2	4.0	3.8	3.7	3.8	4.1	4.8	6.0	4.3	5.8 L	115.2	2.0	1.6	2.0	2.2
KPMG	4.2	7.3	4.1	3.8	4.0	3.9	3.8	3.5	3.3	3.5	3.8	4.4	5.6	na	5.8 L	na	1.9	2.1	0.9	1.6
Nomura Securities, Inc.	4.1	7.3	na	na	na	na	na	3.0	3.2	3.6	na	na	na	na	na	na	0.4 L	1.6	2.8	2.3
The Northern Trust Company	4.1	7.3	4.1	4.2	4.0	3.8	3.8	3.8	3.9	4.1	4.4	5.4	6.5	4.5	6.6	111.0	1.6	2.1	2.1	2.1
Daiwa Capital Markets America	3.9	7.0	na	na	3.8	na	na	3.1	3.1	3.3	4.1	na	na	na	5.9	115.0	1.6	2.4	2.5	2.2
MacroPolicy Perspectives	3.9	7.0	3.8	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na
Georgia State University	3.6	6.7	na	na	3.4	3.1 L	3.1	3.3	3.3	3.7	4.0	4.7	5.8	na	6.2	na	1.8	1.9	1.5	1.4 L
MacroFin Analytics & Rutgers Bus School	3.6	6.9	3.5	3.8	3.4	3.7	4.0	4.3	3.7	3.9	4.3	4.8	5.6	3.8	6.6	114.9	1.8	2.0	2.1	2.1
Societe Generale	3.6	6.8	3.6	na	3.4	3.2	3.0 L	2.9 L	2.7 L	3.2 L	3.5 L	na	na	na	na	na	3.6 H	2.0	2.2	1.8
Scotiabank Group	3.5	na	3.3	na	3.3	na	na	3.4	3.5	4.0	4.2	na	na	na	na	na	1.3	2.1	2.0	2.5
The Lonski Group	3.5	6.7	3.5	3.5	3.6	3.7	3.6	3.6	3.7	3.8	4.0	4.9	5.7	4.0	6.4	119.4	1.8	2.2	2.1	2.0
ING	3.4	na	na	na	na	na	na	3.2	3.4	3.5	3.9	na	na	na	na	na	1.5	na	na	na
NatWest Markets	3.1 L	na	na	3.2	3.4	3.5	3.6	na	na	na	na	na	na	na	na	na	2.0	1.4 L	2.5	2.0
Wells Fargo	3.1 L	6.3 L	3.1 L	3.1 L	3.1 L	3.1 L	3.1	3.1	3.2	3.4	3.8	4.6	5.6	4.0	5.9	na	1.8	2.7	3.1 H	2.7
December Consensus	**4.2**	**7.4**	**4.3**	**4.2**	**4.2**	**4.1**	**4.1**	**3.9**	**3.8**	**4.0**	**4.3**	**5.0**	**6.1**	**4.4**	**6.5**	**115.7**	**1.7**	**2.2**	**2.2**	**2.1**
Top 10 Avg.	4.8	7.9	4.7	4.6	4.7	4.6	4.5	4.4	4.4	4.5	4.7	5.4	6.4	4.7	7.0	117.3	2.3	2.5	2.7	2.5
Bottom 10 Avg.	3.5	6.9	3.8	3.9	3.5	3.6	3.6	3.2	3.2	3.5	3.9	4.7	5.8	4.1	6.1	113.9	1.1	1.8	1.7	1.8
November Consensus	4.1	7.2	4.1	4.1	4.1	4.1	4.0	3.8	3.8	3.9	4.2	5.0	6.1	4.4	6.4	116.7	1.9	2.3	2.3	2.2
Number of Forecasts Changed From A Month Ago:																				
Down	6	4	4	2	8	9	7	6	6	7	4	7	6	7	8	7	11	7	8	8
Same	19	16	13	11	14	9	9	14	14	12	14	5	6	6	5	5	12	14	13	11
Up	10	7	6	5	8	7	9	8	8	10	10	7	6	2	11	3	9	9	10	11
Diffusion Index	56%	56%	54%	58%	50%	46%	54%	54%	54%	55%	61%	50%	50%	33%	56%	37%	47%	53%	53%	55%

International Interest Rate And Foreign Exchange Rate Forecasts

United States

	Fed Fund Target Rate			10 Yr. Gov't Bond Yield %			Fed's AFE $ Index		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	5.13	5.13	5.13	5.00	4.85	4.35	--	--	--
BMO Capital Markets	5.38	5.38	4.88	4.37	4.26	4.13	117.2	117.2	117.0
ING Financial Markets	5.38	4.88	3.88	4.25	4.00	3.50	116.2	114.0	109.1
Moody's Analytics	5.37	5.38	5.09	4.66	4.33	4.13	--	--	--
Northern Trust	5.38	5.38	4.63	4.70	4.70	4.30	117.5	116.0	112.0
Oxford Economics	5.38	5.38	5.35	4.72	4.65	4.27	118.8	119.4	117.7
S&P Global Market Intelligence	--	--	--	4.64	4.43	4.01	--	--	--
Scotiabank	5.38	5.13	3.88	4.50	4.20	4.00	--	--	--
TS Lombard	4.75	3.50	3.50	4.25	4.00	4.00	110.0	108.0	112.0
Wells Fargo	5.38	5.38	4.38	4.30	3.85	3.65	--	--	--
December Consensus	**5.28**	**5.06**	**4.52**	**4.54**	**4.33**	**4.03**	**115.9**	**114.9**	**113.6**
High	5.38	5.38	5.35	5.00	4.85	4.35	118.8	119.4	117.7
Low	4.75	3.50	3.50	4.25	3.85	3.50	110.0	108.0	109.1
Last Months Avg.	5.49	5.36	4.52	4.64	4.39	3.92	119.3	116.4	112.7

Japan

	Policy-Rate Balance Rate			10 Yr. Gov't Bond Yield %			Yen per US$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	-0.10	0.00	0.20	0.90	0.95	1.00	153.0	152.0	145.0
BMO Capital Markets	-0.10	-0.10	-0.10	0.96	0.98	1.00	148.0	146.0	141.0
ING Financial Markets	-0.10	0.00	0.00	1.00	1.00	1.20	140.0	135.0	130.0
Moody's Analytics	-0.10	-0.10	0.00	0.90	0.90	0.90	148.2	144.0	133.6
Nomura Securities	--	--	--	--	--	--	148.0	140.0	135.0
Northern Trust	-0.10	-0.10	0.10	0.80	0.80	1.00	149.0	146.0	140.0
Oxford Economics	-0.04	-0.04	0.00	0.88	0.91	0.87	150.4	152.5	145.0
S&P Global Market Intelligence	--	--	--	--	--	--	148.9	146.4	141.0
Scotiabank	--	--	--	--	--	--	150.0	150.0	140.0
TS Lombard	0.00	0.00	-0.10	0.65	0.40	0.40	145.0	142.4	147.6
Wells Fargo	-0.10	-0.10	0.00	0.95	0.95	0.85	--	--	--
December Consensus	**-0.08**	**-0.06**	**0.01**	**0.88**	**0.86**	**0.90**	**148.1**	**145.4**	**139.8**
High	0.00	0.00	0.20	1.00	1.00	1.20	153.0	152.5	147.6
Low	-0.10	-0.10	-0.10	0.65	0.40	0.40	140.0	135.0	130.0
Last Months Avg.	-0.08	-0.06	-0.05	0.85	0.80	0.66	147.2	142.6	135.3

United Kingdom

	Official Bank Rate			10 Yr. Gilt Yields %			US$ per Pound Sterling		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	5.25	5.25	4.25	4.10	4.10	4.00	1.21	1.23	1.30
BMO Capital Markets	5.25	5.08	4.58	4.39	4.30	4.13	1.26	1.26	1.27
ING Financial Markets	5.25	5.25	4.25	4.25	4.25	3.50	1.23	1.24	1.28
Moody's Analytics	5.25	5.25	5.06	4.26	3.93	3.73	1.25	1.26	1.26
Nomura Securities	--	--	--	--	--	--	1.27	1.28	1.30
Northern Trust	5.25	5.25	4.75	4.30	4.25	3.85	1.24	1.26	1.30
Oxford Economics	5.25	5.25	5.09	4.42	4.39	4.35	1.21	1.21	1.22
S&P Global Market Intelligence	--	--	--	--	--	--	1.22	1.23	1.25
Scotiabank	5.25	4.75	4.25	--	--	--	1.25	1.25	1.30
TS Lombard	5.25	4.25	2.25	4.10	3.85	3.85	1.27	1.20	1.15
Wells Fargo	5.25	4.75	3.75	4.20	3.90	3.55	--	--	--
December Consensus	**5.25**	**5.01**	**4.25**	**4.25**	**4.12**	**3.87**	**1.24**	**1.24**	**1.26**
High	5.25	5.25	5.09	4.42	4.39	4.35	1.27	1.28	1.30
Low	5.25	4.25	2.25	4.10	3.85	3.50	1.21	1.20	1.15
Last Months Avg.	5.28	5.09	4.43	4.52	4.28	3.88	1.22	1.23	1.24

Switzerland

	SNB Policy Rate			10 Yr. Gov't Bond Yield %			CHF per US$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	1.75	1.75	1.25	--	--	--	0.91	0.92	0.91
BMO Capital Markets	1.75	1.75	1.75	--	--	--	0.87	0.86	0.85
ING Financial Markets	1.75	1.75	1.75	1.10	1.10	1.10	0.91	0.90	0.87
Moody's Analytics	2.00	2.00	2.00	1.46	1.96	2.05	0.89	0.88	0.84
Nomura Securities	--	--	--	--	--	--	0.88	0.87	0.86
Northern Trust	1.75	1.75	1.50	1.00	1.00	0.90	0.89	0.87	0.85
Oxford Economics	1.75	1.75	1.63	1.15	1.25	1.34	0.91	0.93	0.92
S&P Global Market Intelligence	--	--	--	--	--	--	0.92	0.91	0.89
Scotiabank	--	--	--	--	--	--	0.89	0.89	0.89
TS Lombard	1.75	1.50	1.25	0.80	0.55	0.55	0.90	0.90	0.90
Wells Fargo	1.75	1.50	1.25	--	--	--	--	--	--
December Consensus	**1.78**	**1.72**	**1.55**	**1.10**	**1.17**	**1.19**	**0.90**	**0.89**	**0.88**
High	2.00	2.00	2.00	1.46	1.96	2.05	0.92	0.93	0.92
Low	1.75	1.50	1.25	0.80	0.55	0.55	0.87	0.86	0.84
Last Months Avg.	1.79	1.75	1.59	1.29	1.31	1.29	0.91	0.90	0.89

Canada

	O/N MMkt Financing Rate			10 Yr. Gov't Bond Yield %			C$ per US$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	5.25	5.25	5.00	--	--	--	1.39	1.38	1.36
BMO Capital Markets	5.00	5.00	4.50	3.64	3.58	3.54	1.33	1.31	1.28
ING Financial Markets	5.00	4.50	3.50	3.50	3.25	3.00	1.35	1.33	1.27
Moody's Analytics	5.00	5.00	4.49	4.39	4.19	4.14	1.36	1.32	1.27
Nomura Securities	--	--	--	--	--	--	1.34	1.33	1.31
Northern Trust	5.00	5.00	4.25	3.75	3.70	3.20	1.38	1.34	1.30
Oxford Economics	5.00	5.00	4.63	4.01	3.97	3.91	1.37	1.38	1.37
S&P Global Market Intelligence	--	--	--	--	--	--	1.35	1.33	1.30
Scotiabank	5.00	4.75	4.00	3.85	3.75	3.65	1.33	1.33	1.28
TS Lombard	5.00	4.00	2.75	3.50	2.25	2.25	1.35	1.35	1.35
Wells Fargo	5.00	4.50	4.00	3.60	3.50	3.30	--	--	--
December Consensus	**5.03**	**4.78**	**4.12**	**3.78**	**3.52**	**3.37**	**1.36**	**1.34**	**1.31**
High	5.25	5.25	5.00	4.39	4.19	4.14	1.39	1.38	1.37
Low	5.00	4.00	2.75	3.50	2.25	2.25	1.33	1.31	1.27
Last Months Avg.	5.03	4.88	4.17	3.91	3.76	3.39	1.35	1.33	1.30

International Interest Rate And Foreign Exchange Rate Forecasts

Australia

	Official Cash Rate			10 Yr. Gov't Bond Yield %			US$ per A$		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	4.35	4.35	3.85	--	--	--	0.63	0.64	0.66
BMO Capital Markets	4.35	4.10	3.60	--	--	--	0.66	0.66	0.67
ING Financial Markets	4.35	4.10	3.60	4.80	4.30	3.70	0.63	0.66	0.72
Moody's Analytics	4.27	4.35	4.10	5.12	4.90	4.36	0.64	0.66	0.72
Nomura Securities	--	--	--	--	--	--	0.68	0.69	0.71
Northern Trust	4.35	4.35	3.85	4.60	4.50	4.10	0.64	0.66	0.68
Oxford Economics	4.40	4.60	4.60	4.60	4.76	4.41	0.64	0.64	0.67
S&P Global Market Intelligence	--	--	--	--	--	--	0.64	0.66	0.69
Scotiabank	--	--	--	--	--	--	0.66	0.66	0.68
TS Lombard	4.10	3.75	2.75	4.40	3.20	3.20	0.65	0.65	0.65
Wells Fargo	4.35	4.35	4.10	--	--	--	--	--	--
December Consensus	**4.32**	**4.24**	**3.81**	**4.70**	**4.33**	**3.95**	**0.65**	**0.66**	**0.69**
High	4.40	4.60	4.60	5.12	4.90	4.41	0.68	0.69	0.72
Low	4.10	3.75	2.75	4.40	3.20	3.20	0.63	0.64	0.65
Last Months Avg.	4.24	4.12	3.76	4.59	4.27	3.69	0.65	0.66	0.68

Euro area

	Main Refinancing Rate			US$ per Euro		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	4.50	4.50	3.50	1.05	1.06	1.09
BMO Capital Markets	4.50	4.25	3.75	1.10	1.11	1.12
ING Financial Markets	4.50	4.25	3.75	1.08	1.10	1.15
Moody's Analytics	4.50	4.50	4.22	1.04	1.06	1.09
Nomura Securities	--	--	--	1.11	1.12	1.14
Northern Trust	4.50	4.25	3.75	1.07	1.10	1.14
Oxford Economics	4.50	4.50	3.75	1.05	1.05	1.06
S&P Global Market Intelligence	--	--	--	1.07	1.09	1.12
Scotiabank	4.50	4.25	3.75	1.10	1.10	1.12
TS Lombard	4.00	2.75	2.75	1.10	1.10	1.10
Wells Fargo	4.00	3.75	3.25	--	--	--
December Consensus	**4.39**	**4.11**	**3.61**	**1.08**	**1.09**	**1.11**
High	4.50	4.50	4.22	1.11	1.12	1.15
Low	4.00	2.75	2.75	1.04	1.05	1.06
Last Months Avg.	4.38	4.22	3.56	1.05	1.06	1.09

10 Yr. Gov't Bond Yields %

	Germany			France			Italy			Spain		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	2.70	2.65	2.25	--	--	--	--	--	--	--	--	--
BMO Capital Markets	2.60	2.49	2.28	--	--	--	--	--	--	--	--	--
ING Financial Markets	2.40	2.30	2.30	3.30	3.20	3.30	4.70	4.40	4.50	3.85	3.60	3.70
Moody's Analytics	2.73	2.67	2.60	3.28	3.15	3.02	4.60	4.60	4.53	3.84	3.77	3.75
Northern Trust	2.65	2.50	2.10	3.15	3.00	2.60	4.35	4.25	3.85	3.60	3.50	3.10
Oxford Economics	2.80	2.73	2.44	3.37	3.29	2.91	4.82	4.72	4.43	3.89	3.80	3.55
TS Lombard	2.40	2.15	2.15	2.75	2.50	2.50	3.70	3.45	3.45	3.15	2.90	2.90
Wells Fargo	2.55	2.50	2.45	--	--	--	--	--	--	--	--	--
December Consensus	**2.60**	**2.50**	**2.32**	**3.17**	**3.03**	**2.87**	**4.43**	**4.28**	**4.15**	**3.67**	**3.51**	**3.40**
High	2.80	2.73	2.60	3.37	3.29	3.30	4.82	4.72	4.53	3.89	3.80	3.75
Low	2.40	2.15	2.10	2.75	2.50	2.50	3.70	3.45	3.45	3.15	2.90	2.90
Last Months Avg.	2.76	2.63	2.44	3.27	3.09	2.88	4.49	4.31	4.10	3.76	3.60	3.42

Consensus Forecasts
10-year Bond Yields vs U.S. Yield

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-3.68	-3.66	-3.47	-3.13
United Kingdom	-0.13	-0.29	-0.21	-0.16
Switzerland	-3.49	-3.44	-3.16	-2.85
Canada	-0.75	-0.76	-0.80	-0.66
Australia	0.08	0.16	0.00	-0.08
Germany	-1.83	-1.94	-1.83	-1.71
France	-1.27	-1.37	-1.30	-1.17
Italy	-0.08	-0.11	-0.04	0.12
Spain	-0.89	-0.87	-0.81	-0.63

Consensus Forecasts
Policy Rates vs U.S. Target Rate

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-5.48	-5.36	-5.01	-4.51
United Kingdom	-0.13	-0.03	-0.05	-0.28
Switzerland	-3.63	-3.50	-3.34	-2.98
Canada	-0.38	-0.25	-0.28	-0.40
Australia	-1.03	-0.97	-0.82	-0.72
Euro area	-0.88	-0.89	-0.95	-0.92

Special Questions:

1. What is your estimate of the long-term neutral fed funds rate?

Consensus	2.90%
Top 10	3.72%
Bottom 10	2.29%

2. Have financial conditions tightened sufficiently to delay/prevent further policy rate increases? Yes 97% No 3%

3. What probability do you attach to a recession beginning over the next 12 months in the:

	US	euro area	UK
Consensus	**44%**	**55%**	**58%**
Top 10	59%	66%	67%
Bot 10	29%	44%	48%

4 a. Does your outlook for China's economy pose meaningful risks to the outlook for global growth? Yes 74% No 26%

b. Do you think recent policy measures in China will boost its growth rate? Yes 37% No 63%

5 a. Has the Federal Reserve completed its tightening cycle? Yes 100% No 0%

b. Has the European Central Bank completed its tightening cycle? Yes 91% No 9%

c. Has the Bank of England completed its tightening cycle? Yes 91% No 9%

6. When will the first hike in the BoJ's short-term policy rate occur?

Q4 2023	0%
Q1 2024	5%
Q2 2024	53%
Q3 2024	21%
Later	21%

Viewpoints: A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

FOMC: On Hold in Restrictive Territory
(Lawrence Werther, Daiwa Capital Markets America)

Since the Fed embarked on its aggressive rate hike campaign in March 2022, we have held the view that a restrictive stance of monetary policy would be required to tame rapid inflation and prevent erosion in inflation expectations of businesses and households. For much of the past year, we had anticipated that the current campaign would culminate in a final increase of 25 basis points in the target range for the federal funds rate to 5.50 to 5.75 percent, with the last change occurring in late 2023, before maintaining the policy rate in restrictive territory for several months. In light of more recent developments, we have become less confident in anticipating any further increase. The FOMC last hiked the federal funds rate in July, and comments by various officials since then, in our view, have turned decidedly more cautious. Moreover, while inflation is still well above target and various indicators suggest that supply and demand imbalances persist in the labor market, we see increasing evidence on both fronts that give officials more leeway to wait for restrictive policy to work.

As of now, and despite the constant reminders from Fed officials that more hikes are possible, we suspect that the FOMC is done tightening monetary policy (i.e., a terminal target range of 5.25 to 5.50 percent). However, while this represents a shift in our Fed call, it is not a material one. We still project policymakers holding the federal funds rate at the terminal rate well into 2024-Q2 to ensure that inflation is convincingly on a path back toward 2%. As inflation decelerates further and the economy struggles amid still-tight financial conditions, we expect the FOMC to begin its slow transition to easier policy. That said, rather than projecting a first cut of 25 basis points to come at the April 30/May 1 FOMC meeting, we now look for the change to occur at the June 11-12 gathering. We then look for the Committee to continue easing by 25-basis-point increments at each of the final four meetings of 2024, leading to a year-end target range of 4.00 to 4.25 percent (consistent with our previous forecast).

Messaging is likely to present a key challenge for officials in coming months despite what we view as a sufficiently restrictive monetary policy. Financial conditions are the primary transmission mechanism of monetary policy to the real economy, and while the economy has responded to tight financial conditions, maintenance of the current constraints on economic activity is essential to achieve desired policy outcomes, i.e., stable prices and maximum sustainable employment. Evidence of the challenge awaiting officials emerged as markets repriced to incorporate evolving expectations for monetary policy. The S&P 500 has rallied more than nine percent since its recent low on October 27, erasing much of the easing in the August-to-October period. Moreover, softening data and the perception that the Fed is done hiking interest rates contributed to a 16-basis-point drop in the 2-year yield from last Friday's close to 4.90 percent and a plunge of 21 basis points in the 10-year yield to 4.44 percent. Consequently, additional easing in financial conditions, despite the maintenance of restrictive policy, could jeopardize further progress toward policy objectives.

A near-term catalyst for movements in financial markets, and key contributory factor in the revision of our Fed call, was data this week that pointed more decidedly toward progress in inflation and easing in tight labor market conditions. On the inflation front, the CPI for October printed below expectations. The headline was flat while the core increased 0.2%. Moreover, risks tilted to the upside as many analysts were concerned that changes to the calculation of health insurance costs in the October report could lead to an upswing in a previously subdued area.

Headline CPI inflation has fallen from a peak of 9.1% in June 2022 to 3.2% in Oct, including a slowing of five ticks in the past month. Energy costs have dropped and increases in food prices have decelerated sharply. Improvement in the core component has been measurable, but less dramatic, as prices rose 4.0% in Oct vs 4.2% in Sep. Additionally, Fed officials rightly view core inflation as still well above the two percent target. Core goods inflation has returned to the pre-2020 trend after the unwinding of pandemic-related supply-demand imbalances (year-over-year growth of 0.1 percent as of October), but more improvement is required in core services where year-over-year growth has slowed from a peak of 7.3 percent in February 2023 but is still elevated at 5.5 percent. Housing costs (illustrated by owners' equivalent rent in the chart) is still a key contributor to core service costs and is widely expected to moderate only over time.

A helpful illustration of near-term progress on inflation is the recent month-to-month performance of the trimmed-mean CPI. (We view this measure as offering a better perspective of underlying inflation as it eliminates price changes at the tails of the monthly distribution.) On a year-over-year basis, this measure has remained elevated (growth of 4.1 percent versus 4.3 percent in September), but the far better near-term performance indicates a more forceful easing in underlying inflation (increases of 0.2 percent in five of the past eight months).

Data on unemployment claims also suggest a slowdown in the real economy that should further dull the underlying inflation impulse, while also emphasizing that risks to the outlook have become more two-sided. That is, the risks of doing too little to combat entrenched inflation must now be weighed against the risks of overtightening and doing unnecessary damage to the economy. While initial claims increased by 13,000 to 231,000 in the week of Nov 11, a reading above the pre-pandemic average of 218,000, which suggested a labor market on firm footing, they were still relatively low from a longer-term perspective. More important, and perhaps somewhat concerning, was the jump of 32,000 in continuing unemployment claims to 1.865 million in the week of Nov 4. Over the past eight weeks, continuing claims have risen by a cumulative 207,000 to the highest level in almost two years. On one hand, this development speaks to an ongoing rebalancing in a tight labor market; on the other hand, it may be the beginning of an uptrend that usually presents prior to the onset of a recession. Again, this development speaks to postponing further hikes, both because policy goals appear more attainable with the current level of monetary restraint and because caution is warranted as the economy possibly nears an inflection point.

Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2025 through 2029 and averages for the five-year periods 2025-2029 and 2030-2034. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		------------------------ Average For The Year ------------------------					Five-Year Averages	
		2025	2026	2027	2028	2029	2025-2029	2030-2034
1. Federal Funds Rate	**CONSENSUS**	**3.8**	**3.2**	**3.1**	**3.0**	**3.0**	**3.2**	**3.0**
	Top 10 Average	4.3	3.6	3.6	3.5	3.5	3.7	3.5
	Bottom 10 Average	3.3	2.7	2.6	2.6	2.5	2.7	2.5
2. Prime Rate	**CONSENSUS**	**6.9**	**6.3**	**6.2**	**6.2**	**6.2**	**6.3**	**6.1**
	Top 10 Average	7.3	6.7	6.7	6.6	6.6	6.8	6.6
	Bottom 10 Average	6.5	5.9	5.7	5.7	5.7	5.9	5.6
3. SOFR	**CONSENSUS**	**3.8**	**3.2**	**3.1**	**3.1**	**3.1**	**3.3**	**3.0**
	Top 10 Average	4.1	3.6	3.5	3.5	3.4	3.6	3.4
	Bottom 10 Average	3.4	2.9	2.7	2.7	2.6	2.9	2.6
4. Commercial Paper, 1-Mo	**CONSENSUS**	**3.7**	**3.2**	**3.2**	**3.2**	**3.1**	**3.3**	**3.1**
	Top 10 Average	3.9	3.5	3.4	3.4	3.4	3.5	3.4
	Bottom 10 Average	3.5	2.9	2.8	2.8	2.8	3.0	2.7
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**3.7**	**3.2**	**3.1**	**3.0**	**3.0**	**3.2**	**3.0**
	Top 10 Average	4.1	3.6	3.6	3.5	3.5	3.7	3.5
	Bottom 10 Average	3.2	2.7	2.6	2.5	2.5	2.7	2.4
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**3.7**	**3.3**	**3.2**	**3.2**	**3.1**	**3.3**	**3.1**
	Top 10 Average	4.1	3.7	3.6	3.6	3.6	3.7	3.6
	Bottom 10 Average	3.4	2.9	2.8	2.7	2.7	2.9	2.7
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**3.7**	**3.4**	**3.3**	**3.3**	**3.2**	**3.4**	**3.2**
	Top 10 Average	4.1	3.8	3.7	3.7	3.7	3.8	3.7
	Bottom 10 Average	3.3	3.0	2.9	2.8	2.8	3.0	2.8
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**3.7**	**3.5**	**3.4**	**3.4**	**3.4**	**3.5**	**3.4**
	Top 10 Average	4.1	3.9	3.9	3.9	3.9	3.9	3.9
	Bottom 10 Average	3.3	3.1	3.0	2.9	2.9	3.0	2.9
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**
	Top 10 Average	4.1	4.1	4.2	4.2	4.3	4.2	4.3
	Bottom 10 Average	3.3	3.2	3.2	3.1	3.1	3.2	3.1
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**
	Top 10 Average	4.3	4.4	4.5	4.5	4.5	4.4	4.5
	Bottom 10 Average	3.5	3.3	3.3	3.3	3.3	3.3	3.3
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**4.1**	**4.1**	**4.1**	**4.2**	**4.2**	**4.1**	**4.2**
	Top 10 Average	4.5	4.6	4.7	4.7	4.7	4.6	4.8
	Bottom 10 Average	3.8	3.6	3.6	3.6	3.6	3.7	3.6
12. Corporate Aaa Bond Yield	**CONSENSUS**	**5.0**	**4.9**	**4.9**	**5.0**	**5.0**	**4.9**	**5.0**
	Top 10 Average	5.3	5.3	5.4	5.5	5.5	5.4	5.5
	Bottom 10 Average	4.6	4.5	4.5	4.5	4.5	4.5	4.4
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**
	Top 10 Average	6.4	6.4	6.5	6.6	6.6	6.5	6.6
	Bottom 10 Average	5.7	5.5	5.5	5.6	5.6	5.6	5.6
14. State & Local Bonds Yield	**CONSENSUS**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**
	Top 10 Average	4.6	4.7	4.7	4.8	4.8	4.7	4.9
	Bottom 10 Average	4.0	3.8	3.9	3.9	3.8	3.9	3.8
15. Home Mortgage Rate	**CONSENSUS**	**6.2**	**5.9**	**5.9**	**5.9**	**5.9**	**5.9**	**5.8**
	Top 10 Average	6.6	6.4	6.4	6.5	6.5	6.5	6.5
	Bottom 10 Average	5.7	5.5	5.4	5.3	5.2	5.4	5.2
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**114.1**	**113.0**	**113.1**	**113.2**	**112.8**	**113.2**	**112.3**
	Top 10 Average	116.0	115.5	115.9	116.5	116.2	116.0	115.7
	Bottom 10 Average	111.8	110.4	110.1	109.6	109.1	110.2	108.5

		--------------------- Year-Over-Year, % Change ---------------------					Five-Year Averages	
		2025	2026	2027	2028	2029	2025-2029	2030-2034
B. Real GDP	**CONSENSUS**	**1.6**	**2.1**	**2.1**	**2.0**	**2.0**	**1.9**	**2.0**
	Top 10 Average	2.1	2.4	2.4	2.3	2.3	2.3	2.3
	Bottom 10 Average	1.1	1.8	1.8	1.7	1.7	1.6	1.7
C. GDP Chained Price Index	**CONSENSUS**	**2.2**	**2.2**	**2.1**	**2.1**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.5	2.3	2.3	2.3	2.3	2.3	2.3
	Bottom 10 Average	2.0	2.0	2.0	2.0	2.0	2.0	2.0
D. Consumer Price Index	**CONSENSUS**	**2.3**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.5	2.4	2.4	2.4	2.4	2.4	2.4
	Bottom 10 Average	2.1	2.1	2.0	2.0	2.0	2.0	2.0
E. PCE Price Index	**CONSENSUS**	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.3	2.3	2.2	2.2	2.2	2.2	2.3
	Bottom 10 Average	2.0	2.0	1.9	1.9	2.0	1.9	2.0

Databank:

2023 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	2.8	-0.7	-0.9	0.4	0.7	0.2	0.6	0.7	0.9	-0.1	····	····
Auto & Light Truck Sales (b)	15.10	14.88	14.93	15.68	15.51	16.06	15.94	15.27	15.68	15.50	····	····
Personal Income (a, current $)	1.0	0.5	0.5	0.2	0.3	0.2	0.3	0.5	0.4	0.2	····	····
Personal Consumption (a, current $)	1.6	0.4	-0.1	0.4	0.2	0.4	0.7	0.4	0.7	0.2	····	····
Consumer Credit (e)	5.1	2.8	4.8	3.3	-0.2	3.1	2.7	-3.8	2.2	····	····	····
Consumer Sentiment (U. of Mich.)	64.9	66.9	62.0	63.7	59.0	64.2	71.5	69.4	67.9	63.8	61.3	····
Household Employment (c)	894	177	577	139	-310	273	268	222	86	-348	····	····
Nonfarm Payroll Employment (c)	472	248	217	217	281	105	236	165	297	150	····	····
Unemployment Rate (%)	3.4	3.6	3.5	3.4	3.7	3.6	3.5	3.8	3.8	3.9	····	····
Average Hourly Earnings (All, cur. $)	33.02	33.11	33.20	33.34	33.45	33.60	33.73	33.82	33.93	34.00	····	····
Average Workweek (All, hrs.)	34.6	34.5	34.4	34.4	34.3	34.4	34.3	34.4	34.4	34.3	····	····
Industrial Production (d)	1.5	0.9	0.2	0.3	0.1	-0.4	0.1	0.1	-0.2	-0.7	····	····
Capacity Utilization (%)	79.6	79.5	79.5	79.8	79.5	78.9	79.6	79.5	79.5	78.9	····	····
ISM Manufacturing Index (g)	47.4	47.7	46.3	47.1	46.9	46.0	46.4	47.6	49.0	46.7	····	····
ISM Nonmanufacturing Index (g)	55.2	55.1	51.2	51.9	50.3	53.9	52.7	54.5	53.6	51.8	····	····
Housing Starts (b)	1.340	1.436	1.380	1.348	1.583	1.418	1.451	1.305	1.346	1.372	····	····
Housing Permits (b)	1.354	1.482	1.437	1.417	1.496	1.441	1.443	1.541	1.471	1.498	····	····
New Home Sales (1-family, c)	649	625	640	679	710	683	728	662	719	679	····	····
Construction Expenditures (a)	2.2	0.4	0.6	0.3	2.0	0.5	0.7	1.0	0.4	····	····	····
Consumer Price Index (nsa, d)	6.4	6.0	5.0	4.9	4.0	3.0	3.2	3.7	3.7	3.2	····	····
CPI ex. Food and Energy (nsa, d)	5.6	5.5	5.6	5.5	5.3	4.8	4.7	4.3	4.1	4.0	····	····
PCE Chain Price Index (d)	5.5	5.2	4.4	4.4	4.0	3.2	3.4	3.4	3.4	3.0	····	····
Core PCE Chain Price Index (d)	4.9	4.8	4.8	4.8	4.7	4.3	4.3	3.8	3.7	3.5	····	····
Producer Price Index (nsa, d)	5.7	4.7	2.7	2.3	1.1	0.3	1.2	2.1	2.2	1.3	····	····
Durable Goods Orders (a)	-1.3	-2.7	3.3	1.2	2.0	4.3	-5.6	-0.1	4.0	-5.4	····	····
Leading Economic Indicators (a)	-0.5	-0.5	-1.2	-0.8	-0.7	-0.7	-0.2	-0.4	-0.7	-0.8	····	····
Balance of Trade & Services (f)	-70.8	-70.6	-60.4	-73.0	-66.8	-63.7	-64.7	-58.7	-61.5	····	····	····
Federal Funds Rate (%)	4.33	4.57	4.65	4.83	5.06	5.08	5.12	5.33	5.33	5.33	····	····
3-Mo. Treasury Bill Rate (%)	4.69	4.79	4.86	5.07	5.31	5.42	5.49	5.56	5.56	5.60	····	····
10-Year Treasury Note Yield (%)	3.53	3.75	3.66	3.46	3.57	3.75	3.90	4.17	4.38	4.80	····	····

2022 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	1.4	1.4	2.1	1.3	-0.1	0.8	-0.7	0.7	-0.3	1.4	-1.4	-0.7
Auto & Light Truck Sales (b)	14.38	13.67	13.58	14.04	12.94	13.27	13.49	13.50	13.70	14.68	14.27	13.55
Personal Income (a, current $)	-0.3	0.6	0.4	0.3	0.4	0.4	0.8	0.5	0.4	0.5	0.1	0.2
Personal Consumption (a, current $)	0.5	0.7	1.2	0.6	0.4	1.0	0.0	0.8	0.6	0.6	-0.1	0.3
Consumer Credit (e)	4.6	8.3	10.1	7.3	6.9	8.6	6.8	7.0	6.9	8.8	8.1	4.8
Consumer Sentiment (U. of Mich.)	67.2	62.8	59.4	65.2	58.4	50.0	51.5	58.2	58.6	59.9	56.7	59.8
Household Employment (c)	1041	468	738	-346	317	-242	215	422	156	-257	-66	717
Nonfarm Payroll Employment (c)	364	904	414	254	364	370	568	352	350	324	290	239
Unemployment Rate (%)	4.0	3.8	3.6	3.6	3.6	3.6	3.5	3.7	3.5	3.7	3.6	3.5
Average Hourly Earnings (All, cur. $)	31.63	31.63	31.83	31.94	32.06	32.18	32.33	32.43	32.53	32.66	32.80	32.92
Average Workweek (All, hrs.)	34.6	34.7	34.7	34.6	34.6	34.6	34.6	34.5	34.6	34.6	34.5	34.4
Industrial Production (d)	2.3	6.6	4.4	4.6	3.7	3.2	3.0	3.1	4.5	3.1	1.9	0.6
Capacity Utilization (%)	79.4	79.9	80.5	80.7	80.6	80.5	80.7	80.7	80.8	80.6	80.3	78.9
ISM Manufacturing Index (g)	57.6	58.4	57.0	55.9	56.1	53.1	52.7	52.9	51.0	50.0	49.0	48.4
ISM Nonmanufacturing Index (g)	60.4	57.2	58.4	57.5	56.4	56.0	56.4	56.1	55.9	54.5	55.5	49.2
Housing Starts (b)	1.669	1.771	1.713	1.803	1.543	1.561	1.371	1.505	1.463	1.432	1.427	1.357
Housing Permits (b)	1.898	1.817	1.877	1.795	1.708	1.701	1.658	1.586	1.588	1.555	1.402	1.409
New Home Sales (1-family, c)	810	773	707	611	636	563	543	638	567	577	582	636
Construction Expenditures (a)	2.4	1.5	1.4	1.8	-0.1	-0.4	-0.2	-1.2	-0.6	-0.4	0.6	-0.1
Consumer Price Index (nsa, d)	7.5	7.9	8.5	8.3	8.6	9.1	8.5	8.3	8.2	7.7	7.1	6.5
CPI ex. Food and Energy (nsa, d)	6.0	6.4	6.5	6.2	6.0	5.9	5.9	6.3	6.6	6.3	6.0	5.7
PCE Chain Price Index (d)	6.3	6.5	6.9	6.6	6.7	7.1	6.6	6.5	6.6	6.3	5.9	5.4
Core PCE Chain Price Index (d)	5.4	5.6	5.5	5.3	5.1	5.2	5.0	5.2	5.5	5.3	5.1	4.9
Producer Price Index (nsa, d)	10.1	10.4	11.7	11.2	11.1	11.2	9.7	8.7	8.5	8.2	7.4	6.4
Durable Goods Orders (a)	2.0	-1.4	-0.1	1.0	0.7	1.6	-0.8	-0.1	0.3	1.0	-3.1	4.5
Leading Economic Indicators (a)	-0.5	0.3	0.0	-0.6	-0.9	-0.7	-0.6	-0.3	-0.5	-0.9	-0.9	-0.7
Balance of Trade & Services (f)	-86.5	-87.0	-102.5	-86.0	-84.1	-80.9	-71.7	-67.3	-71.7	-78.3	-63.8	-71.4
Federal Funds Rate (%)	0.08	0.08	0.20	0.33	0.77	1.21	1.68	2.33	2.56	3.08	3.78	4.10
3-Mo. Treasury Bill Rate (%)	0.15	0.31	0.45	0.76	0.99	1.54	2.30	2.72	3.22	3.87	4.32	4.36
10-Year Treasury Note Yield (%)	1.76	1.93	2.13	2.75	2.90	3.14	2.90	2.90	3.52	3.98	3.89	3.62

(a) month-over-month % change; (b) millions, saar; (c) month-over-month change, thousands; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level. Most series are subject to frequent government revisions. Use with care.

Calendar of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
December 4 Manufacturers' Shipments, Inventories & Orders (Oct) BEA Auto Sales (Nov) BEA Truck Sales (Nov) NABE Outlook (Q4)	**5** JOLTS (Oct) ISM Services PMI (Nov) S&P Global Services PMI (Nov)	**6** ADP Employment Report (Nov) Productivity & Costs (Q3) Intl Trade (Oct) Transportation Services Index (Oct) QFR (Q3) Public Debt (Nov) Interest on Public Debt (Nov) EIA Crude Oil Stocks Mortgage Applications	**7** Wholesale Trade (Oct) Treasury Auction Allotments (Nov) Consumer Credit (Oct) Financial Accounts (Q3) Challenger Employment Report (Nov) Weekly Jobless Claims	**8** Employment Situation (Nov) Consumer Sentiment (Dec, Preliminary)
11 Kansas City Financial Stress Index (Nov)	**12** CPI & Real Earnings (Nov) QSS (Q3) Cleveland Fed Median CPI(Nov) Monthly Treasury Statement (Nov) Manpower Survey (Q1) NFIB (Nov) Kansas City Fed Labor Market Conditions Indicators (Nov) FOMC Meeting	**13** Producer Prices (Nov) FOMC Meeting OPEC Crude Oil Spot Prices (Nov) EIA Crude Oil Stocks Mortgage Applications	**14** Advance Retail Sales (Nov) Import & Export Prices (Nov) MTIS (Oct) Weekly Jobless Claims	**15** IP & Capacity Utilization (Nov) ECEC (Q3) Empire State Mfg Survey (Dec) Livingston Survey (Apr) Housing Affordability (Oct)
18 Business Leaders Survey (Dec) Home Builders (Dec)	**19** New Residential Construction (Nov) TIC Data (Oct)	**20** International Transactions (Q3) Existing Home Sales (Nov) Consumer Confidence (Dec) EIA Crude Oil Stocks Mortgage Applications	**21** GDP & Corp Profits (Q3, 3rd Estimate) Philadelphia Fed Mfg Business Outlook Survey (Dec) Kansas City Fed Manufacturing Survey (Dec) Composite Indexes (Nov) Weekly Jobless Claims	**22** Personal Income (Nov) Underlying NIPA Tables (Q3, 3rd Estimate) Advance Durable Goods (Nov) New Residential Sales (Nov) Building Permits (Nov) Consumer Sentiment(Dec, Final) Dallas Fed Trim-Mean PCE (Nov) Treas Auction Allotments (Dec) S&P Global Flash PMIs (Dec)
25 **CHRISTMAS DAY** **ALL MARKETS CLOSED**	**26** FHFA HPI (Oct) Case-Shiller HPI (Oct) H.6 Money Stock (Nov) Philadelphia Fed Nonmfg Business Outlook (Dec) Chicago Fed National Activity Index (Nov) Texas Mfg Outlook (Dec)	**27** Richmond Fed Mfg & Service Sector Surveys (Dec) Texas Service Sector Outlook Survey (Dec) Mortgage Applications	**28** Adv Trade & Inventories (Nov) Intl Investment Position (Q3) Steel Imports for Consumption (Nov, Preliminary) Pending Home Sales (Nov) EIA Crude Oil Stocks Weekly Jobless Claims	**29** Agricultural Prices (Nov) Strike Report (Dec) Chicago PMI (Dec) FRB Philadelphia Coincident Economic Activity Index (Nov)
January 1 **NEW YEAR'S DAY** **ALL MARKETS CLOSED**	**2** Construction (Nov) Dallas Fed Banking Conditions Survey (Nov) S&P Global Mfg PMI (Dec)	**3** ISM Manufacturing (Dec) JOLTS (Nov) Mortgage Applications	**4** ADP Employment Report (Dec) Challenger Employment Report (Dec)| S&P Global Services PMI (Dec) BEA Auto & Truck Sales (Dec) EIA Crude Oil Stocks Weekly Jobless Claims	**5** Employment Situation (Dec) MSIO (Nov) Public Debt (Dec) Interest Expense on Public Debt (Dec) ISM Services PMI (Dec)
8 Consumer Credit (Nov)	**9** International Trade (Nov) NFIB (Dec) Kansas City Financial Stress Index (Dec)	**10** Wholesale Trade (Nov) EIA Crude Oil Stocks Mortgage Applications	**11** CPI & Real Earnings (Dec) Cleveland Fed Median CPI(Dec) Monthly Treasury Statement (Dec) Weekly Jobless Claims	**12** Producer Prices (Dec)

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Markets

Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks

By Justina Lee
March 11, 2021, 10:08 AM EST

- ▶ Investors fear sector has morphed into a big bet on low rates
- ▶ Yet history shows tech's link with bonds is far more complex

Don't fear Treasury yields killing off the stock market's golden goose just yet.

As the Nasdaq 100 Index recovers from a $1.5 trillion rout, there's good reason to think technology shares can defy machinations in U.S. bonds.

Studies from Deutsche Bank AG and Goldman Sachs Group Inc. show the world's biggest equity sector has a fickle relationship with Treasuries, if it has one at all. Quant powerhouse AQR Capital Management has found little evidence that yields drive how expensive megacaps trade relative to their cheaper counterparts.

And of course, secular economic trends have been powering the likes of Facebook Inc. and Amazon.com Inc. for years now -- when benchmark rates were far higher than current levels.

All that makes the Treasury-stock link more complex than it seems.

Low-Rate Trade?
Higher yields have made tech large-caps an underperformer lately

Source: Bloomberg

Put another way, while the recent Treasury selloff has pummeled Big Tech, that doesn't mean bonds are a natural foe for a sector hitched to secular trends from 5G to automation.

"Many tech companies will continue to benefit for many years from very strong themes that will result in outsized earnings growth," said Terry Ewing, head of equities at Mediolanum International Funds, which oversees about $54 billion. "The dilemma for portfolio managers running a balanced mandate is that actually the de-rating we've seen in growth stocks has put them at a much more attractive level."

Ewing's funds began offloading a handful of tech stocks for cyclical names from the third quarter, just as rising expectations for an economic re-opening pushed yields higher in the world's biggest bond market.

As the U.S. yield curve steepened last month, $1.5 trillion of value was wiped off tech shares, while assets deemed less sensitive to duration risk like value stocks -- banks, oil drillers and commodity producers -- surged.

The Nasdaq 100 jumped nearly 2% on Thursday morning in New York, as 10-year Treasury yields traded little changed around 1.5%.

Quant Perspective

From the perspective of quants who dissect equities by their factors, there are a few ways to explain the last month's rotation.

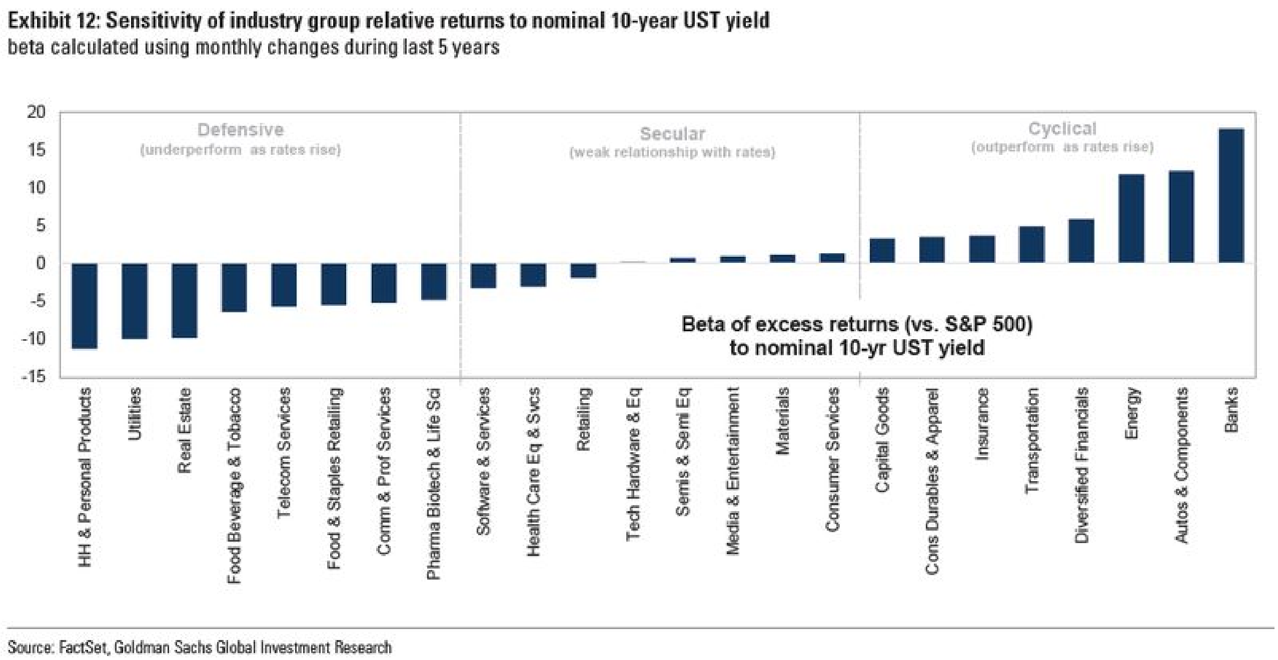
Technology companies are typically dubbed growth stocks thanks to their strong expected profit expansion, often far into the future. That's in contrast to value shares, which trade with lower multiples due to their riskier businesses.

When rates fall, economic growth is typically muted. That makes a company like Netflix Inc. look like a a safer bet since it's riding the secular trend of streaming rather than ups and downs of the business cycle. Meanwhile the likes of Exxon Mobil Corp., tied to oil demand, look riskier.

In the post-crisis era of monetary easing, that's how the valuation dynamic played out: Netflix's long-term earnings were discounted at lower rates -- making it more expensive.

Now, opposing forces are in play. Rising yields are making the near-term cash flows of cheaper equities like Exxon Mobil more attractive.

"Sooner or later we will see pretty decent economic growth," said Georg Elsaesser, a quant portfolio manager at Invesco. "I would be more than surprised if that wouldn't be favorable for high-risk factors like value."



Source: Goldman Sachs

Yet all these relationships are volatile -- and have far less explanatory power than commonly asserted.

Interest-rate changes only explain 19% of the returns posted by the growth factor versus value since 2018, Goldman Sachs strategists wrote in a note last month. That compares with 54% for cyclicals versus defensive.

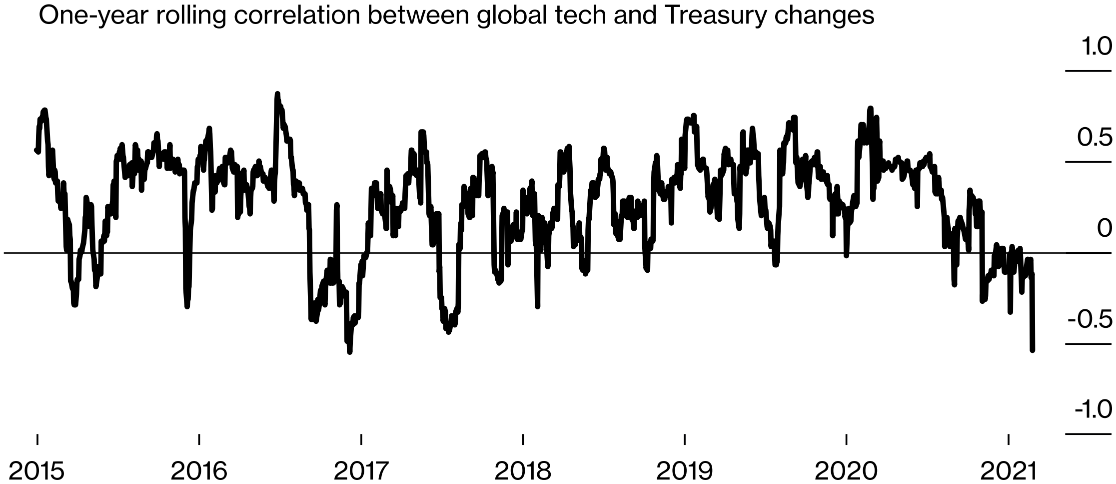
In other words, industry-specific trends, not bonds, seem to be driving this tech-heavy part of the market.

Similarly Deutsche Bank's quants find a zero beta, or sensitivity, between bonds and tech since 2015. In contrast, financials and energy had the most positive links with yields, and utilities and real estate the most negative.

According to Andreas Farmakas, a quantitative strategist at Deutsche Bank, this shows how the tech sector and Treasuries lack a direct and consistent link. In fact, these stocks in the past often rose with rates, with the latter seen as a sign of economic strength that could benefit corporate earnings.

It's Complicated

Tech stocks' relationship with Treasuries has been volatile in the short run



Source: Deutsche Bank
Data show one-year rolling correlation between daily moves in global tech and in 10-year Treasury yields

That's not to say there isn't reason to fret recent co-movements.

"Given the ties between technology, the overbought Covid trade and ultimately equity indices -- they take up a large chunk -- the correlation flipped," Farmakas said.

In other words, bonds have lately turned from friend to foe -- and that's why quants like Invesco's Elsaesser are so reluctant to time markets.

For its part, AQR last year called the link between interest rates and value -- which involves a bet against growth -- "suspect" since it varies greatly depending on the period, the markets and measurements studied.

All this suggests that once the initial reflation frenzy settles, there's no reason to fear bond yields will necessarily doom the tech trade. In fact Ewing at Mediolanum is eyeing some bargains in the months ahead.

"Somewhere along the second-half of this year going into next year it'll be prudent for investors to start considering moving to higher-quality names rather than cyclical recovery," he said.

In this article

GS
GOLDMAN SACHS GP
343.12 USD ▲ +1.10 +0.32%

DBK
DEUTSCHE BANK-RG
10.52 EUR ▼ -0.20 -1.88%

CL1
WTI Crude
65.45 USD/bbl. ▲ +1.01 +1.57%

NFLX
NETFLIX INC
512.64 USD ▲ +8.10 +1.60%

XOM
EXXON MOBIL CORP
62.46 USD ▲ +0.69 +1.11%

Commentary | Third Quarter 2023

Investment Research Update

From the desk of

Denise Chisholm
Director of Quantitative Market Strategy

Fidelity INVESTMENTS

Performance Summary: Technology Takes the Lead

Investors weighed a shifting outlook during the second quarter, as inflation fell but stayed high, the U.S. Federal Reserve raised interest rates more slowly, and a bank crisis unfolded. The information technology, communication services, and consumer discretionary sectors led the stock market during the quarter as investors turned their focus to cyclical stocks. Utilities, energy, and consumer staples were the bottom performers for the quarter.

Sector	Performance as of 06/30/23				Weight in S&P 500®
	Latest Quarter	1-Year	3-Year Annualized	Dividend Yield	
Communication Services	13.1%	17.3%	7.3%	0.8%	8.4%
Consumer Discretionary	14.6%	24.7%	9.0%	0.9%	10.7%
Consumer Staples	0.5%	6.6%	11.9%	2.5%	6.7%
Energy	-0.9%	18.8%	35.4%	3.8%	4.1%
Financials	5.3%	9.5%	15.6%	1.8%	12.4%
Health Care	3.0%	5.4%	11.7%	1.6%	13.4%
Industrials	6.5%	25.2%	18.0%	1.6%	8.5%
Information Technology	17.2%	40.3%	20.0%	0.8%	28.3%
Materials	3.3%	15.1%	16.0%	2.0%	2.5%
Real Estate	1.4%	-4.4%	6.1%	3.4%	2.5%
Utilities	-2.5%	-3.7%	8.4%	3.2%	2.6%
S&P 500®	8.7%	19.6%	14.6%	1.5%	

Past performance is no guarantee of future results. Sectors defined by the Global Industry Classification Standard (GICS®); see Index Definitions for details. Performance metrics reflect S&P 500 sector indexes. Changes were made to the GICS framework on 9/24/18; historical S&P 500 communication services sector data prior to 9/24/18 reflect the legacy telecommunication services sector. The top three performing sectors over each period are shaded green; the bottom three are shaded red. It is not possible to invest directly in an index. All indexes are unmanaged. Percentages may not total 100% due to rounding.

Source: Haver Analytics, Morningstar, FactSet, Fidelity Investments, as of 06/30/2023.

Scorecard: Several Cyclical Sectors Look More Attractive

The signals appear mixed overall. That said, there may be a higher margin of safety in several cyclically oriented sectors, mainly due to relative valuations. With core inflation continuing decline at the end of the quarter, and rates appearing nearer to the end of the tightening cycle, sectors including consumer discretionary, and industrials may offer opportunities.

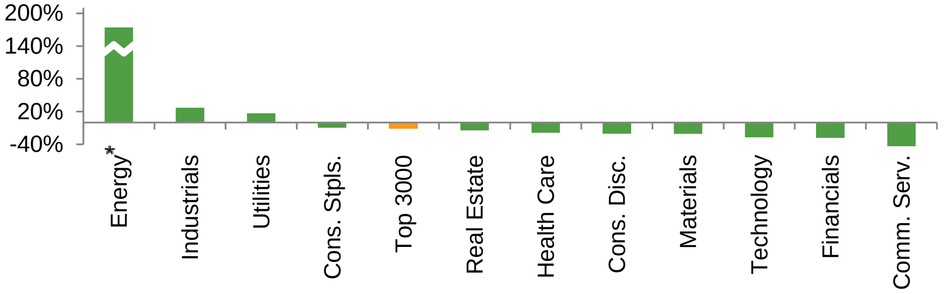
Sector	Strategist View (🟩 Overweight ◼ Neutral 🟥 Underweight)	Time Horizon View: Longer — Fundamentals	Valuations	Shorter — Relative Strength	Comments
Communication Services	🟥	–	–	+	Defensive characteristics may hinder performance
Consumer Discretionary	🟩		–	+	Increasingly constructive contrarian indicators, median valuation compelling
Consumer Staples	🟥	+			Earnings growth likely to lag in a broader recovery
Energy	🟥	+	+	–	Increasingly mixed signals from macro and fundamental
Financials	🟩	–	+	–	Relative valuation may limit further deterioration
Health Care	🟩				Good combination of fundamentals and valuation
Industrials	🟩	+			Other predictive valuation indicators still compelling
Information Technology	🟩		–	+	Earnings increasingly likely to recover
Materials	🟩			–	Valuation and economic indicators are supportive
Real Estate	🟥	–	+		Elevated valuation likely to be a headwind
Utilities	🟥				Defensive characteristics may hinder performance

Past performance is no guarantee of future results. Strategist view, fundamentals, valuations, and relative strength are based on the top 3,000 U.S. stocks by market capitalization. Sectors defined by the GICS; see Index Definitions for details. Historical communication services data has been restated back to 1962 to account for changes to the GICS framework made on 9/24/18. **Strategist view** is as of the date indicated based on the information available at that time and may change based on market or other conditions. This is not necessarily the opinion of Fidelity Investments or its affiliates. Fidelity does not assume any duty to update any of the information. Overweight and underweight views represent opportunistic tilts in a hypothetical portfolio relative to broad market sector weights. Sector weights may vary depending on an individual's risk tolerance and goals. Time horizon view factors are based on historical analysis and are not a qualitative assessment by any individual investment professional. The top three sectors based on each time horizon view metric are shaded green; the bottom three are shaded red. See Glossary and Methodology for details. It is not possible to invest directly in an index. All indexes are unmanaged. Source: Haver Analytics, FactSet, Fidelity Investments, as of 6/30/2023.

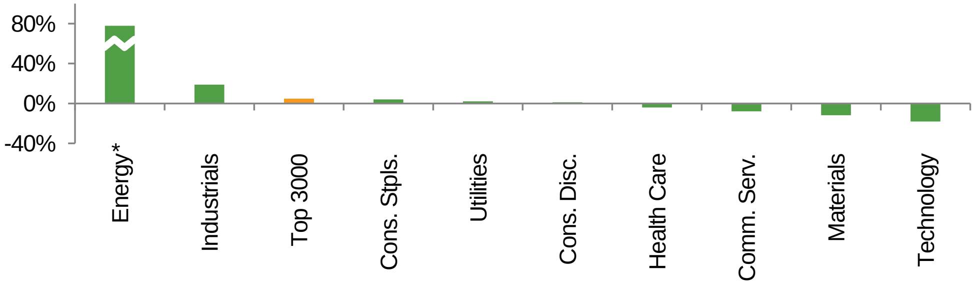
Fundamentals: Energy, Industrials, and Consumer Staples Led

Energy led the fundamentals rankings, coming in first in earnings per share (EPS) growth, EBITDA (earnings before interest, taxes, depreciation, and amortization) growth, and return on equity (ROE). The industrials and consumer staples also scored well. Financials was the worst performing sector, ranking 10th in EPS growth and eighth in ROE. Real estate and communications services also posted relatively poor fundamentals.

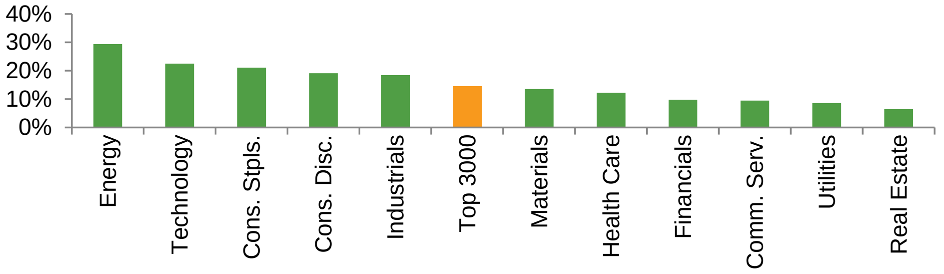
EPS Growth (Last 12 Months)



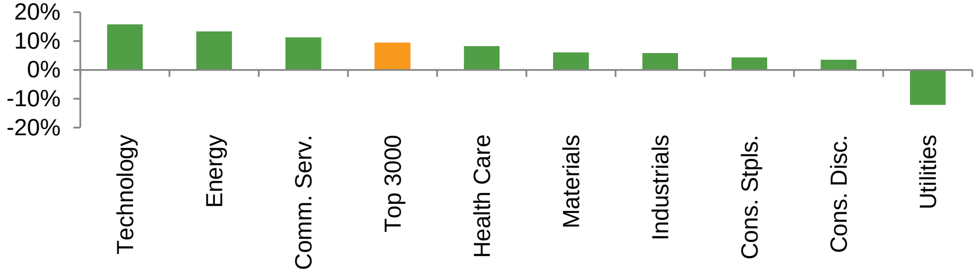
EBITDA Growth (Last 12 Months)



Return on Equity (Last 12 Months)



Free-Cash-Flow Margin (Last 12 Months)



Fundamentals: Strong and improving fundamentals historically have been an intermediate-term indicator of sector performance. Our analysis gives a view of how each sector has done in terms of growth and profitability.

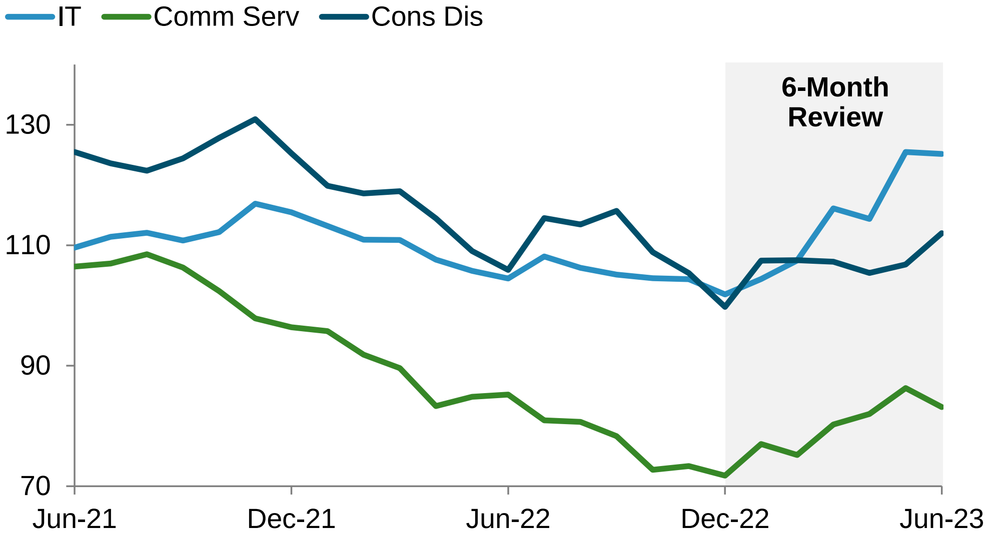
Past performance is no guarantee of future results. EPS = earnings per share. EBITDA = earnings before interest, taxes, depreciation, and amortization. * EPS growth value over the last 12 months for energy was 2,789%; EBITDA Growth for energy over the same period was 167%. The financials and real estate sectors are not represented in the EBITDA growth or free-cash-flow margin charts because of differences in their business models and accounting standards. See Glossary and Methodology for further explanation Sectors based on the top 3,000 U.S. stocks by market capitalization and defined by GICS. Communication services data restated back to 1962.
Source: Haver Analytics, Fidelity Investments, as of 6/30/23.

Relative Strength in Technology, Communications and Consumer

The technology, communication services and consumer discretionary sectors exhibited the greatest strength based on our relative price momentum score the past six months. Financials, materials and energy exhibited weakness based on relative price momentum.

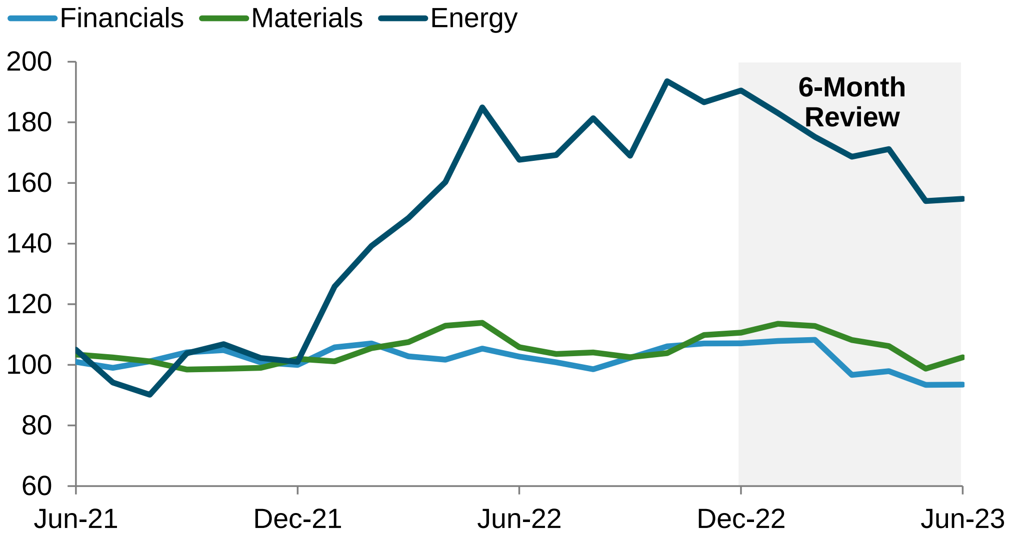
Sectors Exhibiting Relative Strength

Price Relative to the Russell 3000 Index



Sectors Exhibiting Relative Weakness

Price Relative to the Russell 3000 Index



Relative Strength: Stocks and sectors that have outperformed the broader market have tended to continue to do so.

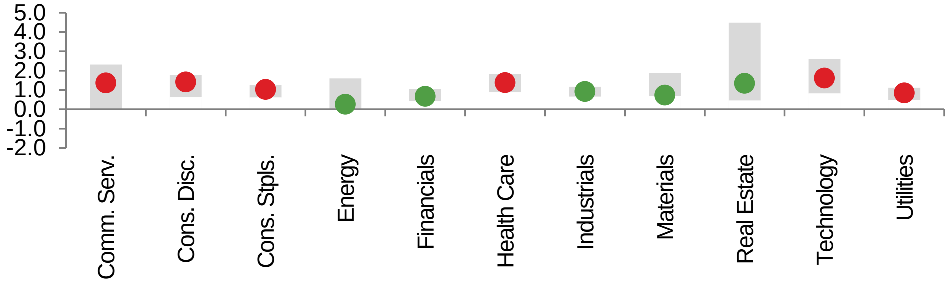
Past performance is no guarantee of future results. Relative strength compares the performance of each sector with the performance of the broad market, based on changes in the ratio of the securities' respective prices over time. See Glossary and Methodology for further explanation. Charts represent performance of sectors based on the top 3,000 stocks by market capitalization relative to the Russell 3000 Index. It is not possible to invest directly in an index. All indexes are unmanaged. Source: FactSet, Fidelity Investments, as of 11/30/22.

Valuations: Energy, Real Estate, and Financials Looked Cheap

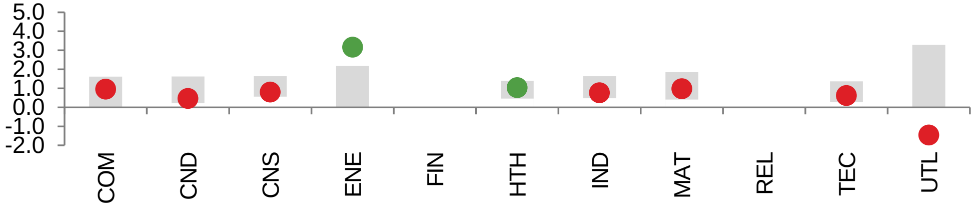
Energy had the cheapest quarter-end valuations, ranking least expensive in price-to-earnings and free-cash-flow yield. Real estate and financials also looked relatively inexpensive for the quarter. Consumer discretionary, technology, and communication services had the highest aggregate valuations.

Historical Range   Current: Green/Red = Cheap/Expensive Relative to Historical Average

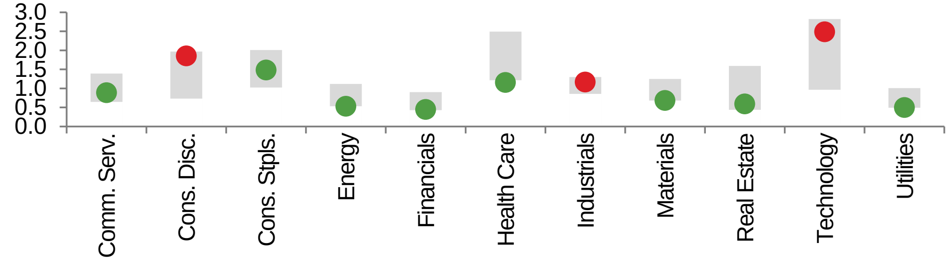
Price-to-Earnings Ratio; Forward Price/Earnings Ratio Relative to Top 3,000 Stocks



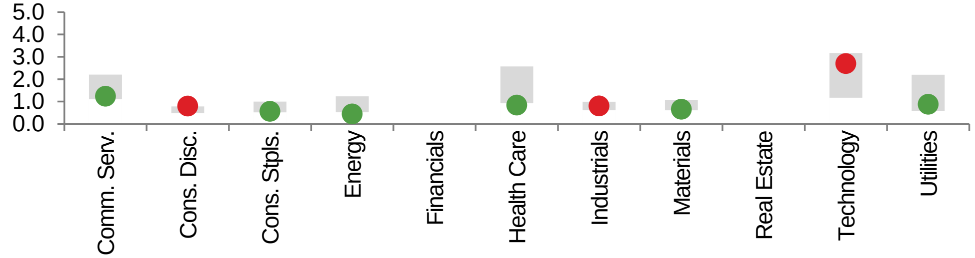
Free-Cash-Flow Yield; Free-Cash-Flow Yield Relative to Top 3,000 Stocks



Price-to-Book Ratio; Forward Price/Book Ratio Relative to Top 3,000 Stocks



Price-to-Sales Ratio; Forward Price/Sales Ratio Relative to Top 3,000 Stocks



Valuations: On their own, valuations are only a moderately effective indicator of future sector performance, but when combined with other factors, they can be a useful tool in determining the risk-and-reward profile.

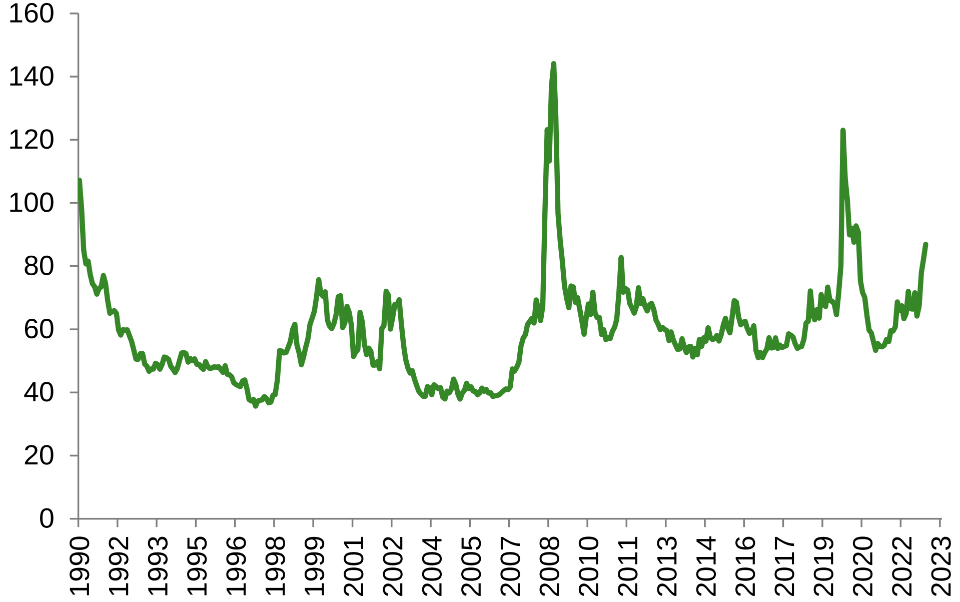
Past performance is no guarantee of future results. Free-cash-flow yield reflects free cash flow divided by market price per share; it is the inverse of the price-to-free-cash-flow ratio. Historical range excludes the top and bottom 5%. Green or red circles indicate if current levels are below or above the historical average, which excludes the top and bottom 5%. The financials and real estate sectors are not represented in the free-cash-flow yield or price-to-sales charts because of differences in their business models and accounting standards. See the Glossary and Methodology for further explanation. Historical range since January 1962. Sectors based on the top 3,000 U.S. stocks by market capitalization and defined by GICS. Communication services data restated back to 1962. Source: Haver Analytics, Fidelity Investments, as of 6/30/23.

High Valuation Spreads Consistently Signaled Strong Returns

At the end of May, valuation spreads—the gap in valuation between the cheapest and most expensive groups of stocks in the Russell 3000 Index based on quartiles of book yield—were in the top 5% of the market's historical range going back to late 1990 (left). Stocks in this broad-based index historically posted strong average gains after valuation spreads reached this extreme (right).

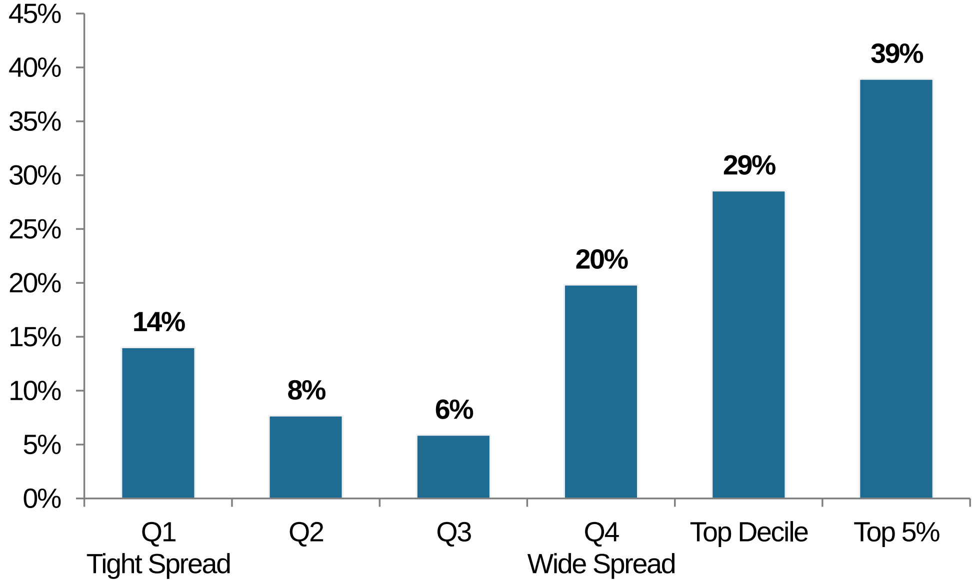
High Valuation Spreads Suggested Investor Fear

Russell 3000 Book Yield Spread, December 1990–May 2023



Consistently Strong Returns Followed High Valuation Spreads

NTM Russell 3000 Returns in Cohorts of Russell 3000 Valuation Spreads, December 1990–May 2023



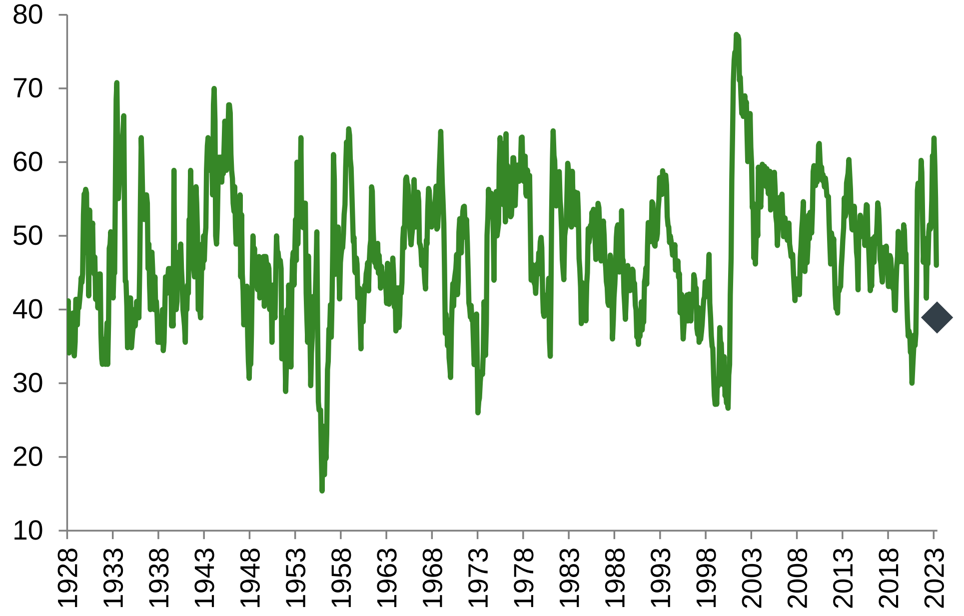
Past performance is no guarantee of future results. Data analyzed monthly since December 1990. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 5/31/23. **LEFT:** Book yield: The ratio of book value per share to price per share. Book yield spread: The difference between the median book yields of the Russell 3000's most-expensive and least-expensive quartiles. **RIGHT:** NTM: Next twelve months.

A Narrow Market Preceded Stock Gains in the Past

Fewer than 40% of the stocks in the S&P 500 outperformed the index for the trailing 12 months through May. This marked the narrowest rolling 12-month market breadth since 2020 and among the narrower breadth readings going back to the late 1920s. Narrow breadth often is viewed as a negative sign for the stock market's health, although this view has not been supported by history: Since 1928, the narrower the market breadth, the higher the index returns tended to be over the next 12 months—even when the S&P 500 already had advanced (right).

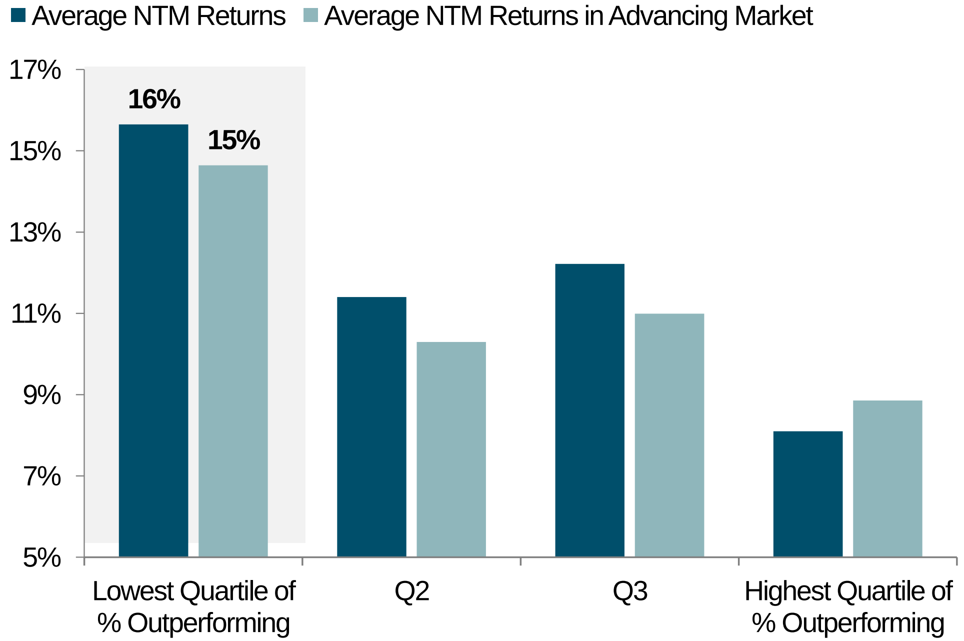
Few Stocks Have Powered the Market's Returns

Market Breadth: Percent of S&P 500 Companies Outperforming the Index, LTM, January 1928–May 2023



Stocks Have Gained after Poor Market Breadth Readings

Rolling NTM S&P 500 Returns, 1928–May 2023



Past performance is no guarantee of future results. Data analyzed monthly since 1928. Analysis based on the S&P 500. Market breadth measured by the percentage of stocks outperforming the index. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 5/31/23. **LEFT:** LTM: Last 12 months. **RIGHT:** NTM: Next 12 months.

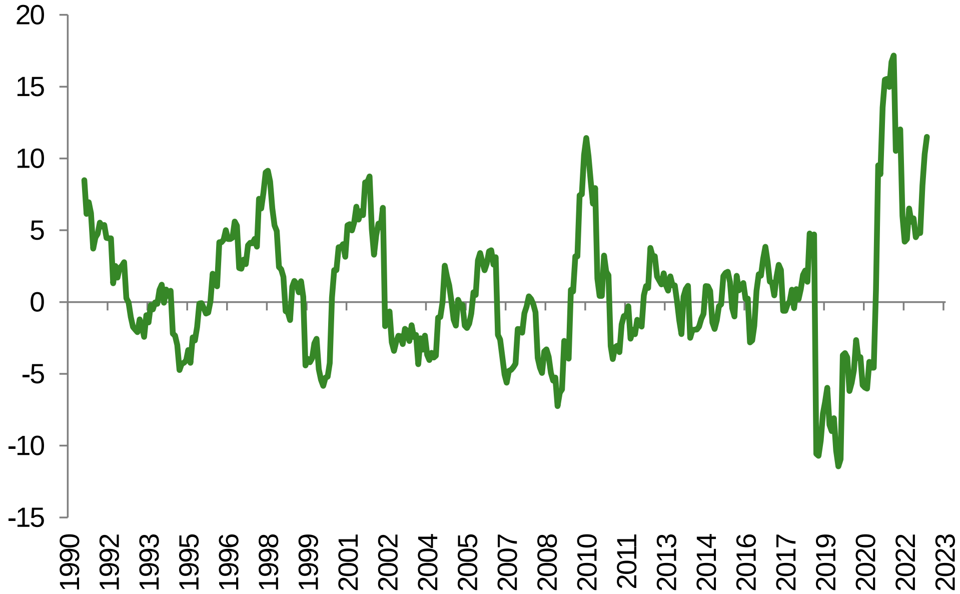
Fidelity INVESTMENTS

Mid Cap Earnings Were Up and Valuations Were Down

Earnings for mid cap stocks in the S&P 400 index increased quicker than those for stocks in the large cap S&P 500 index since mid-2021 (left). Stronger relative earnings growth helped make mid caps historically cheap relative to large caps (right). Stocks in the consumer discretionary, technology, and industrials sectors were the least-expensive mid caps based on relative price-to-book ratios.

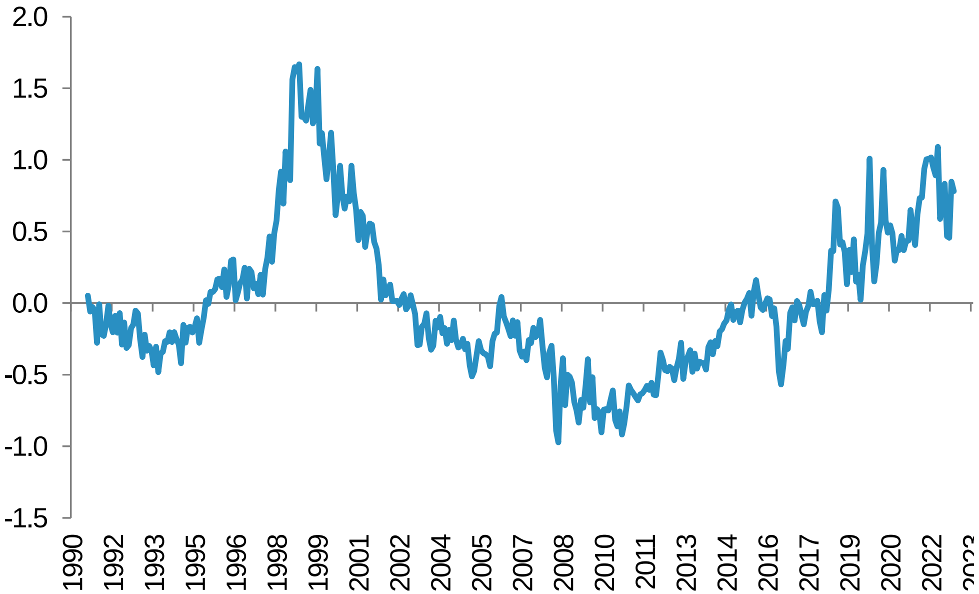
Mid Cap Earnings Grew Much Faster than Large Cap Earnings

Median EPS Growth in the S&P MidCap 400 vs. the S&P 500,
December 1990–May 2023



Mid Caps Looked Cheaper Than Large Caps

Median Forward EPS Yield in the S&P MidCap 400 vs. the S&P 500
(Higher Is Cheaper), December 1990–May 2023



Past performance is no guarantee of future results. EPS: Earnings per share. Analysis based on the S&P 400 and S&P 500. Data analyzed monthly since December 1990. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 5/31/23. **RIGHT**: Earnings yield is the inverse of the price-earnings ratio.

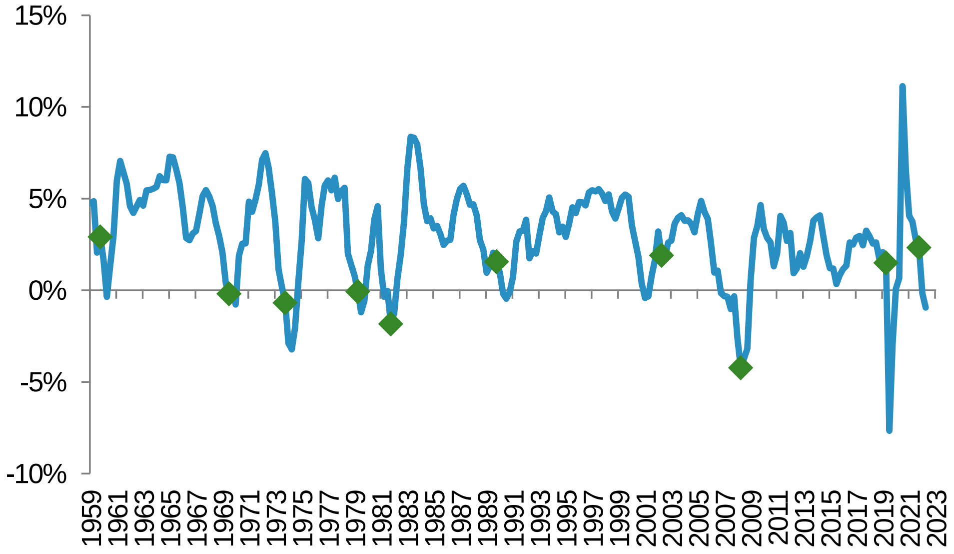
Real GDI and Inflation Fell—Historically a Good Sign for Stocks

Real gross domestic income (GDI), which measures inflation-adjusted total U.S income in all economic sectors, contracted over the four quarters through March 2023. For much of this time, inflation decelerated from its mid-2022 peak. Since 1959, stocks often started recovering roughly around the time real GDI turned negative (left) and, in many cases, around peaks in the annual inflation rate, measured by the Consumer Price Index (right). The pattern fits the current stock market rally, which started in October.

Stocks Often Bottomed Before Real GDI Downturns

Year-Over-Year Change in Real Gross Domestic Income and Stock Market Troughs, 1959–March 2023

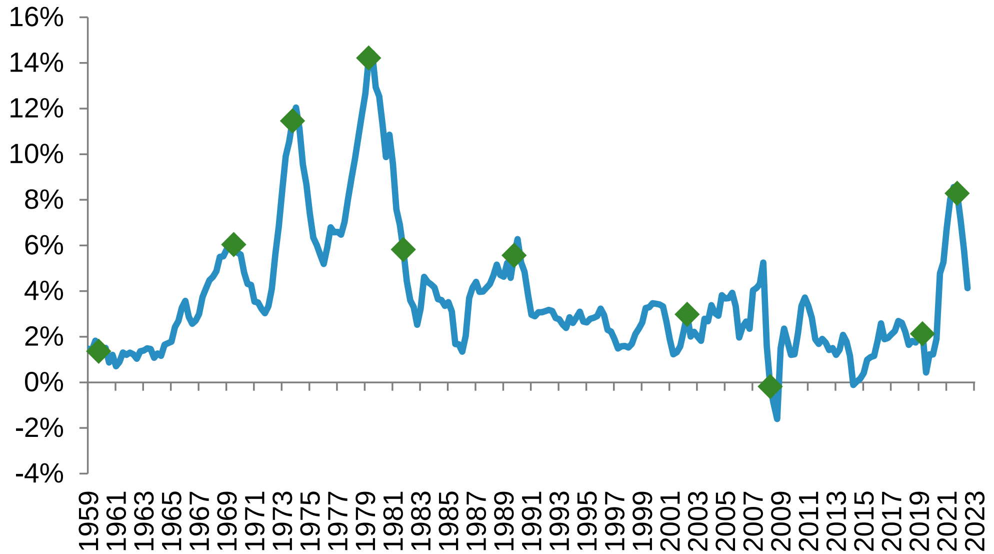
Real Gross Domestic Income Y/Y % Change ◆ Recessionary Stock Market Trough



Market Recoveries Frequently Started Near Peaks in Inflation

Year-Over-Year Consumer Price Index and Stock Market Troughs, 1959–March 2023

CPI-U: All Items Y/Y % Change ◆ Recessionary Stock Market Trough



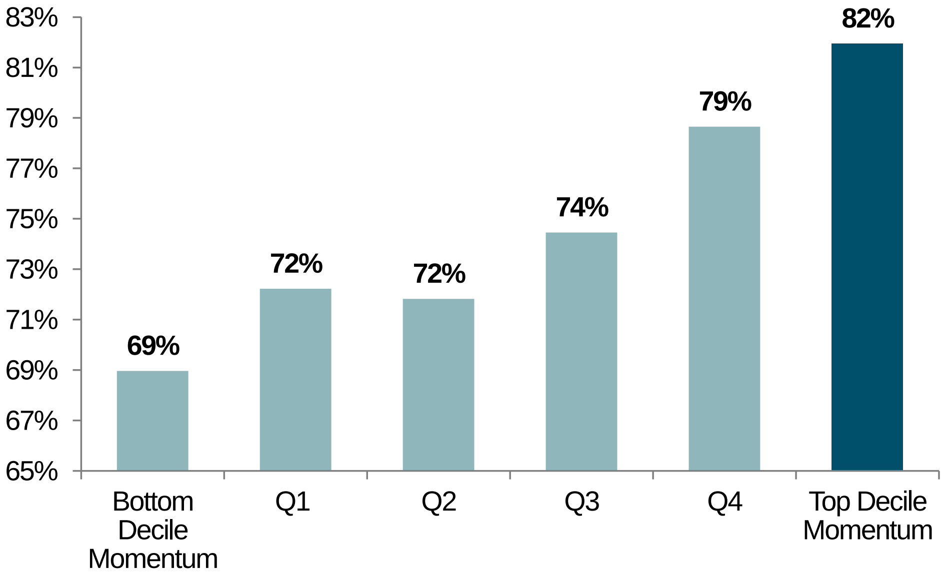
Past performance is no guarantee of future results. Data analyzed quarterly since Q4 1959. Analysis based on the S&P 500. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 5/31/23. **LEFT**: Real gross domestic income is an inflation-adjusted measure of total income earned and costs incurred in the production of gross domestic product (GDP) in all economic sectors. **RIGHT:** CPI is the consumer price index, which seeks to measure the rate of change for price inflation among urban consumers.

Technology Stocks Surged, Historically a Bullish Sign for the Market

U.S. technology stocks* gained 13% in April, easily reaching the top decile of one-month tech sector returns since 1962. Over this historical span, top-decile monthly tech sector returns have tended to coincide with strong forward 12-month returns for the overall market (left). Also in this time frame, cyclicals were more likely than defensive sectors to outperform the top 3,000 stocks (right).

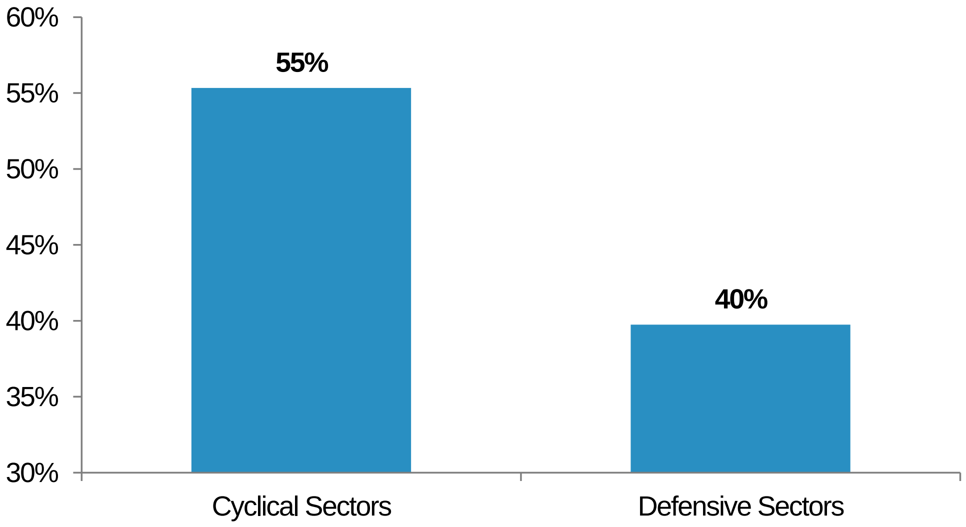
Strong Months for Technology, Up Years for the Market

Rolling Odds of NTM Market Advance in Quartiles and Deciles of Prior One-Month Technology Sector Price Percent Change, 1962–Present



Cyclicals Tended to Lead after One-Month Tech Surges

Rolling NTM Odds of Average Defensive and Cyclical Sector Outperformance After Top-Decile One-Month Tech Returns, 1962–April 2023



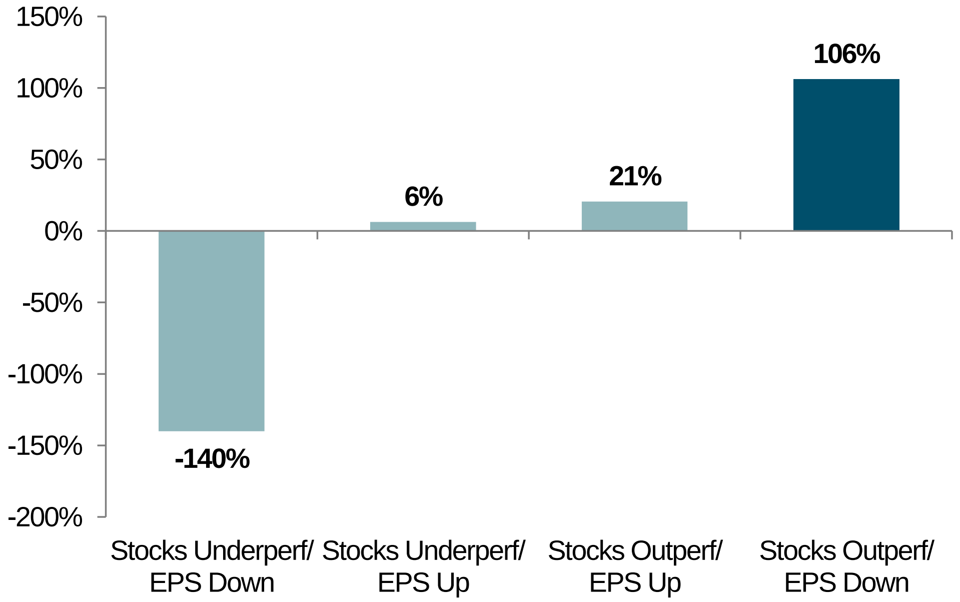
Past performance is no guarantee of future results. NTM: Next twelve months. *Analysis based on U.S. technology stocks within a Fidelity list of the top 3,000 stocks by market capitalization. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 4/30/23. Data analyzed monthly since 1962. Deciles include 58 observations. Quartiles include 180 observations. **RIGHT:** Cyclical sectors include communication services, consumer discretionary, energy, financials, industrials, materials, real estate, and technology. Defensive sectors include consumer staples, health care, and utilities.

Tech Stocks Outperformed amid Poor Earnings. What's Next?

Tech earnings contracted for the 12 months through May, yet the sector outperformed the broad market over this span. Historically, the market has been good at sniffing out tech-sector rebounds: After 12-month periods when tech had negative earnings and outperformed, the sector's average profits more than doubled over the next 12 months (left), and tech stocks outperformed by an average of 7% (right).

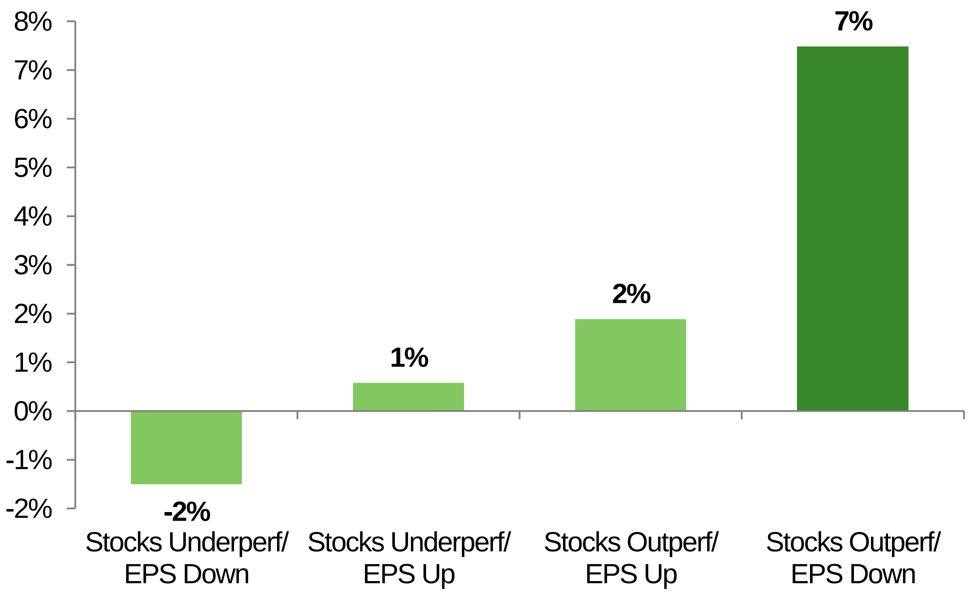
Tech Outperformance Came before Earnings Recoveries

Rolling Average NTM EPS Growth in Combinations of Relative Performance and EPS Growth, 1962–May 2023



After Beating the Market with Weak Earnings, Tech Outperformed

Rolling Average NTM Tech Sector Relative Performance in Combinations of Relative Performance and EPS, 1962–May 2023



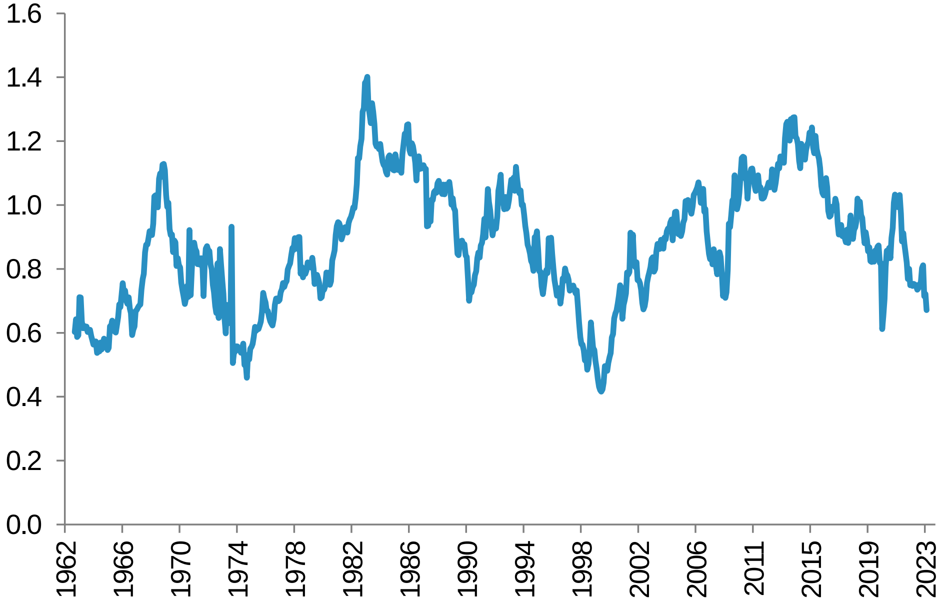
Past performance is no guarantee of future results. NTM: Next twelve months. EPS: Earnings per share. Analysis based on a Fidelity list of the top 3,000 stocks by market capitalization. Number of observations (left to right): 94, 214, 291, 85. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 4/30/23. Data analyzed monthly since 1962.

Low Discretionary Valuations Signaled Outperformance Before

As of May, the consumer discretionary sector's valuation based on price-to-book ratio relative to the rest of the market reached about 0.7, bringing the sector's relative valuation to its lowest quartile going back to (left). Previously, when the sector reached a bottom-quartile relative price-to-book ratio, discretionary stocks outperformed the market by 4% over the next 12 months (right).

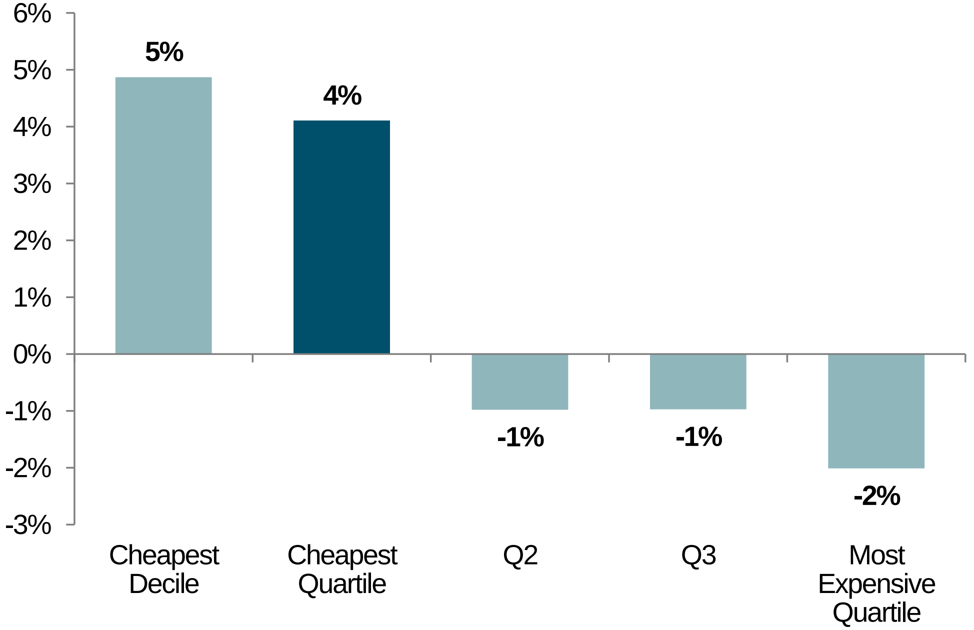
Consumer Discretionary Valuations Fell Near Pandemic Lows

Equal Weighted Consumer Discretionary Relative Price-to-Book, 1962–May 2023



Discretionary Outperformed After Bottom-Quartile Relative Valuations

Rolling NTM Relative Performance of Equal Weighted Consumer Discretionary in Quartiles of Relative Price/Book Valuation, 1962–Present



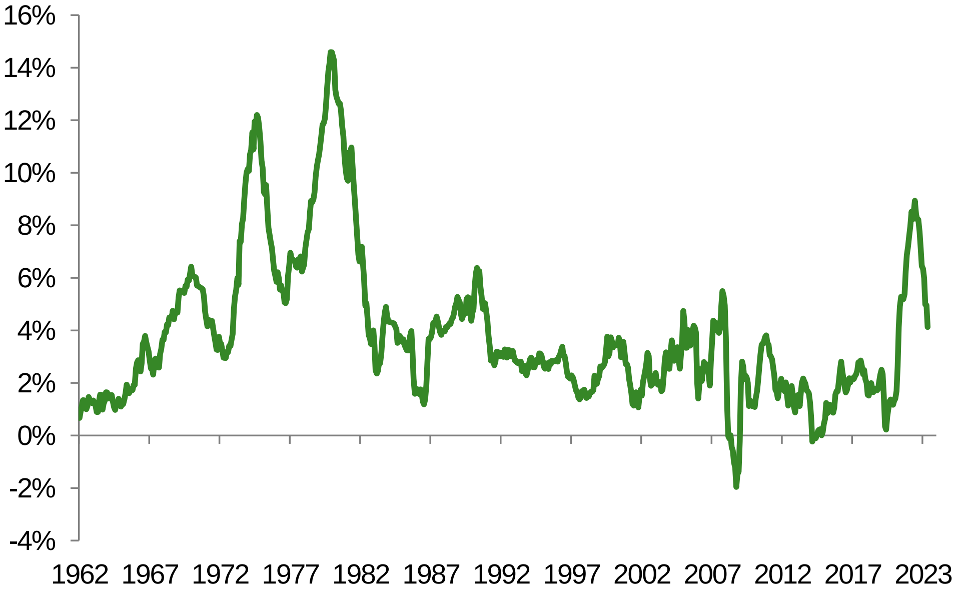
Past performance is no guarantee of future results. P/Book: Price-to-book. Equal-weighted indexes weight all stocks equally rather than by market capitalization so the largest consumer discretionary stocks do not have undue influence on results. Analysis based on a Fidelity list of the top 3,000 stocks by market capitalization. Data analyzed monthly since 1962. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 5/31/23.

Consumers' Real Income Increased

Inflation has fallen steadily since the middle of 2022 (left), helping real income growth accelerate and boosting consumers' ability to spend. Since 1962, falling inflation has been good for consumer discretionary stocks, on average (right).

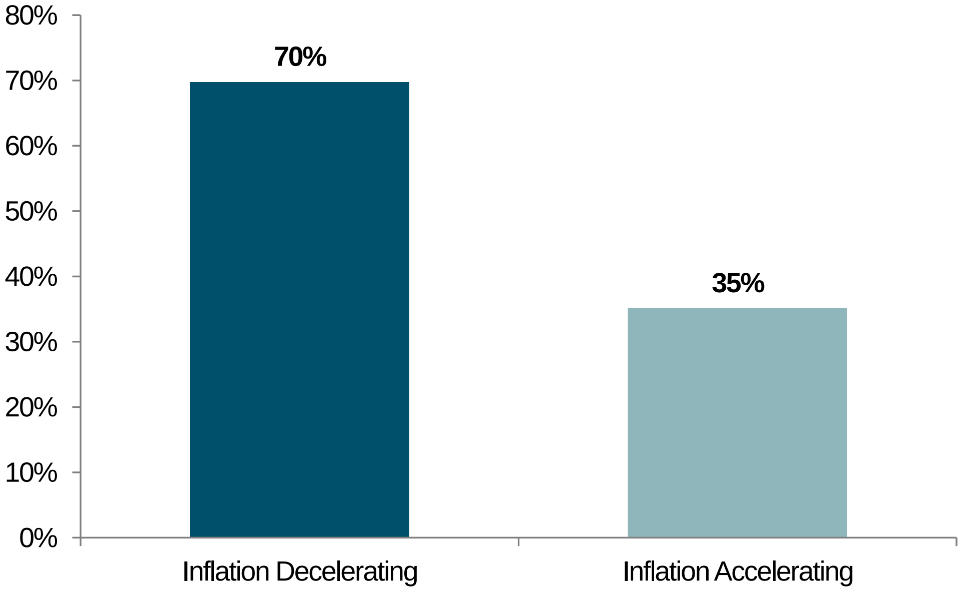
Inflation Decelerated Fast

CPI-U Percent Year-to-Year Change, January 1962–May 2023



Discretionary Historically Outperformed amid Falling Inflation

Average 12-Month Odds of Outperformance, January 1962–May 2023



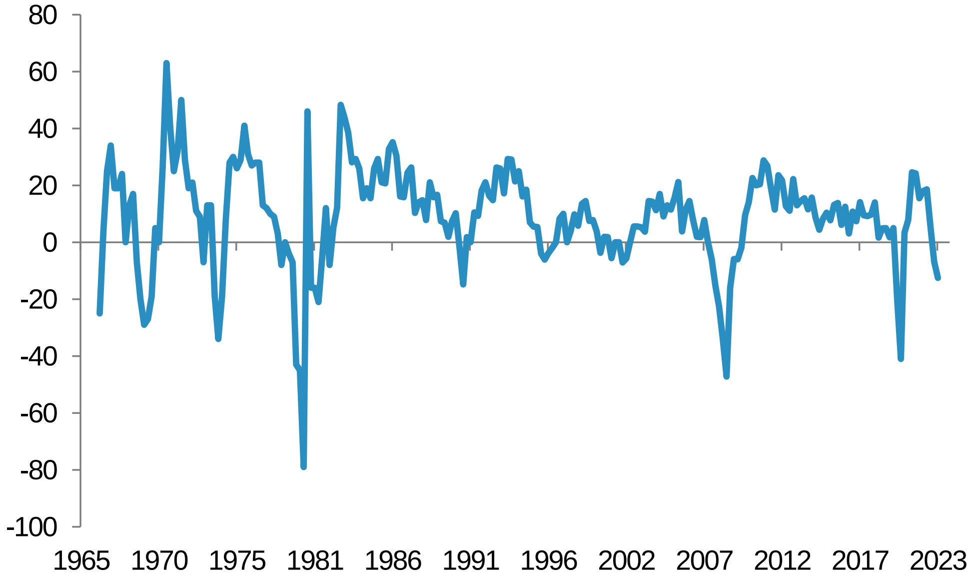
Past performance is no guarantee of future results. Data analyzed monthly since 1962. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 5/31/23.
LEFT: CPI-U: Consumer Price Index for All Urban Consumers. **RIGHT:** Analysis based on consumer discretionary stocks in a Fidelity list of the top 3,000 stocks by market capitalization. Inflation decelerated in 324 12-month periods observed and accelerated in 376 12-month periods observed.

Discretionary Outperformed After Tight Lending Before

Following the collapse of several regional banks in March, banks tightened lending standards to the bottom decile of their historical range going back to 1966 (left). It may seem counterintuitive, but in the past, after the willingness of banks to lend reached the bottom historical decile, consumer discretionary was the most likely sector to beat the market over the next 12 months, with consistent outperformance across sub-sectors (right).

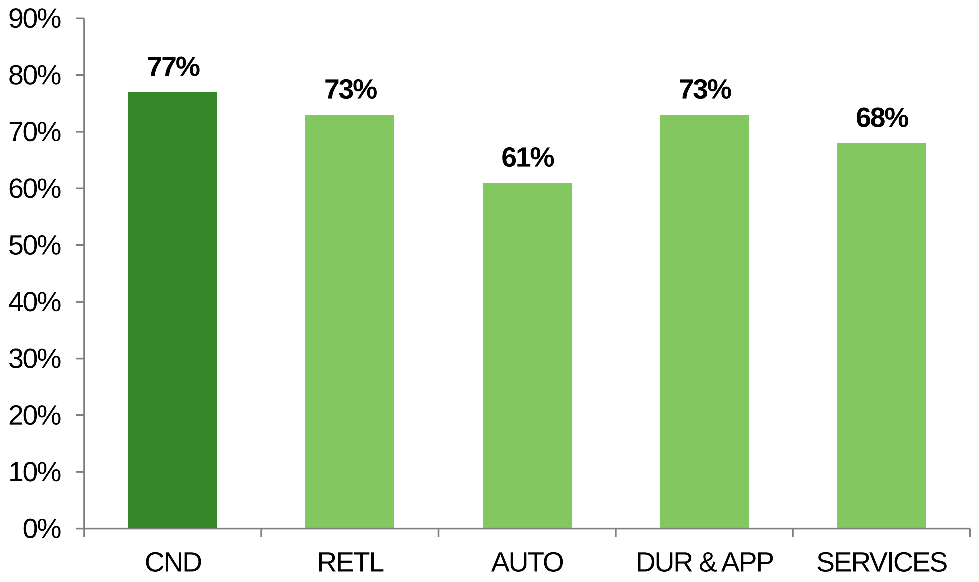
Banks Tightened Consumer Lending Standards

FRB Senior Officers Survey Banks Willingness to Lend to Consumers, June 1966–May 2023



The Surprise Winner after Tight Lending: Consumer Discretionary

Rolling NTM Odd of Outperformance after Bottom Decile Willingness to Lend, June 1966–May 2023



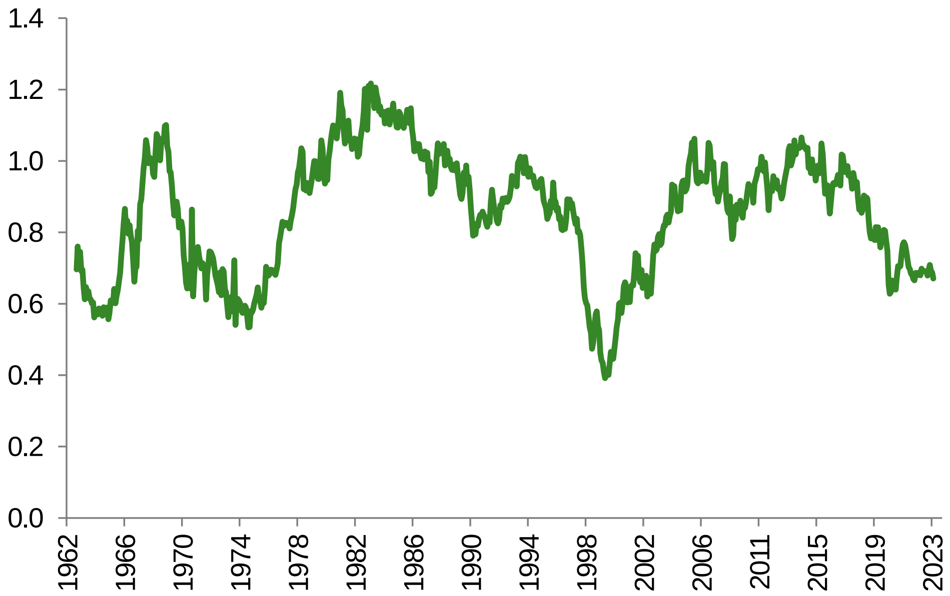
Past performance is no guarantee of future results. Data analyzed quarterly since June 1966. Analysis based on Fidelity top 3,000 stocks by market capitalization. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 4/30/23. **LEFT:** FRB Senior Officers Survey: Federal Reserve Board Senior Loan Officer Opinion Survey. **RIGHT:** NTM: Next twelve months. There were 58 instances of 12-month returns after bottom-decile willingness to lend during this period. CND: Consumer discretionary. RETL: Retail. AUTO: Automotive. DUR & APP: Durables and apparel. SERVICES: Consumer services.

Industrials Got Cheap

Industrials looked inexpensive as of May, with valuations falling to their bottom historical quartile going back to early 1962, based on price-to-book ratio relative to the market (left). Historically, when the sector reached bottom-quartile relative price-to-book, it outperformed the market 71% of the time over the next 12 months (right).

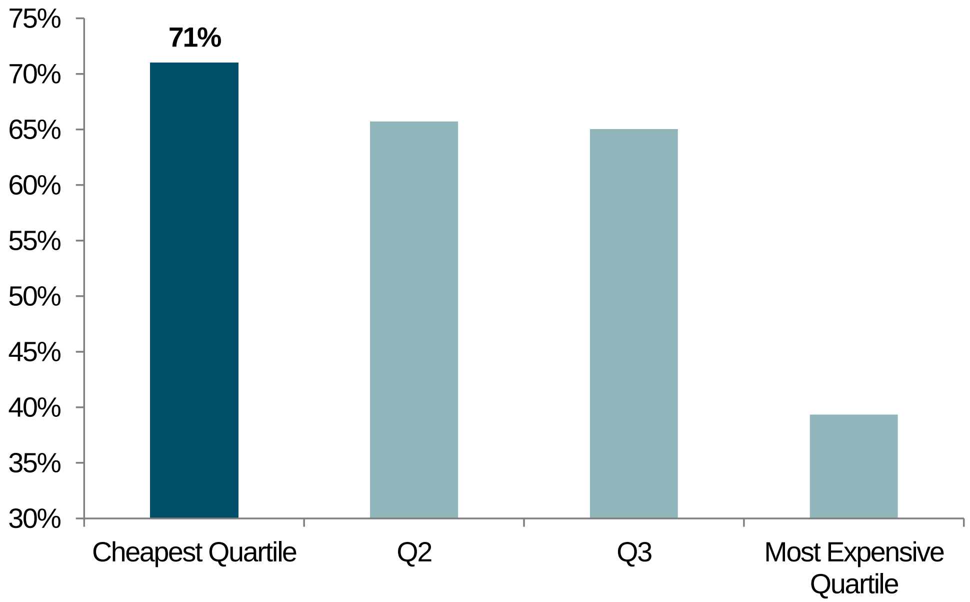
Industrials' Valuations Fell

Equal-Weighted Industrials' Relative Price-to-Book, January 1962–May 2023



Industrials Outperformed after Being Inexpensive

Equal Weighted Industrials' Odds of Outperformance, Rolling NTM, after Relative Price-to-Book Valuation Cohorts, January 1962–May 2023



Past performance is no guarantee of future results. Analysis based on a Fidelity list of the top 3,000 stocks by market capitalization. Data analyzed monthly since 1962. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 5/31/23. **LEFT:** Equal-weighted indexes weight all stocks equally rather than by market capitalization so the largest stocks do not have undue influence on results. Analysis based on a Fidelity list of the top 3,000 stocks by market capitalization. **RIGHT:** NTM: Next twelve months.

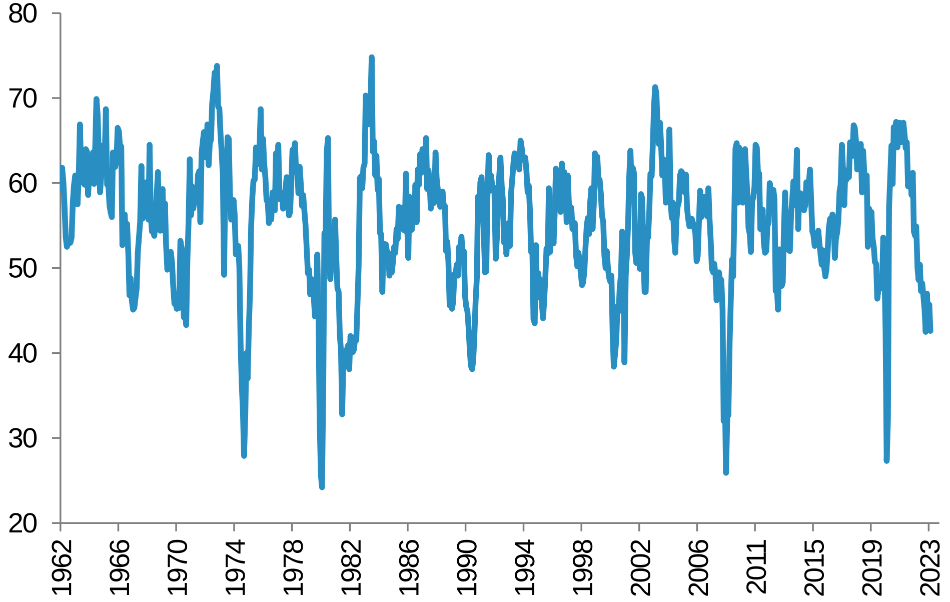
Fidelity INVESTMENTS

Weak Manufacturing Didn't Doom Industrials in the Past

Manufacturing has been weak, according to the Institute for Supply Management (ISM) Manufacturing New Orders Index (left), which recently fell to the lowest 5% of its historical range since 1962. This may not be the headwind some investors fear. When the ISM manufacturing index reached this historical nadir in the past, industrials had 71% odds of outperforming the market over the next 12 months (right).

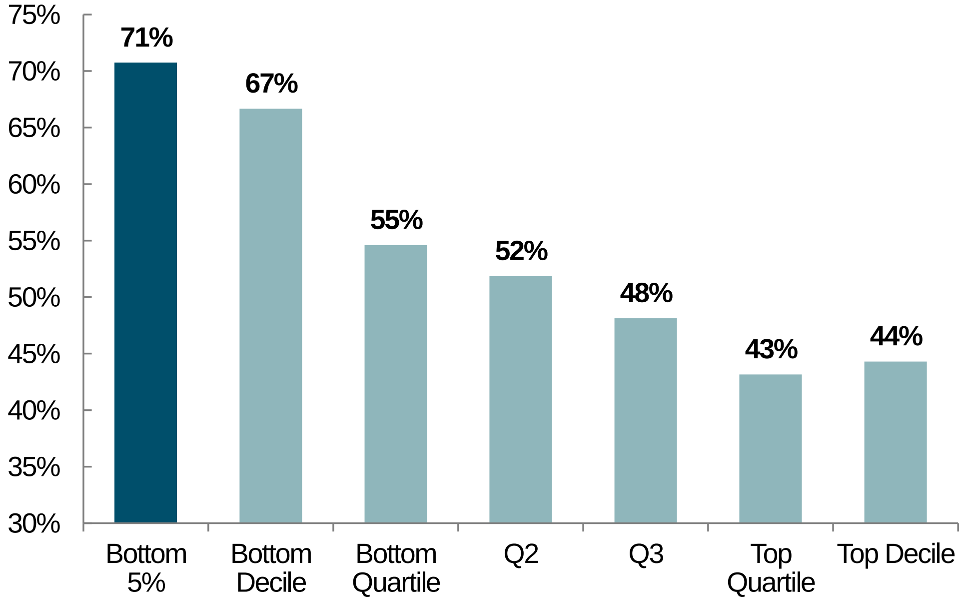
Manufacturing Slumped

ISM Manufacturing New Orders Index, January 1962–May 2023



Industrials Outperformed after Manufacturing Downturns

NTM Odds of Outperformance in Quartiles and Deciles of ISM New Orders, January 1962–May 2023



Past performance is no guarantee of future results. Analysis based on Fidelity top 3,000 stocks by market capitalization. Data analyzed monthly since January 1962. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 5/31/23. **LEFT:** ISM: Institute for Supply Management. A reading below 50 in the ISM manufacturing index indicates contraction. **RIGHT:** NTM: Next twelve months. Number of observations: top 5%, 24; each decile, 58; each quartile, 180.

Glossary and Methodology

Glossary

Cycle Hit Rate: Calculates the frequency of a sector outperforming the broader equity market over each business cycle phase since 1962.

Dividend Yield: Annual dividends per share divided by share price.

Earnings before Interest, Taxes, Depreciation, and Amortization (EBITDA): A non-GAAP measure often used to compare profitability between companies and industries, because it eliminates the effects of financing and accounting decisions.

Earnings-per-Share Growth: Measures the growth in reported earnings per share over the specified past time period.

Earnings Yield: Earnings per share divided by share price. It is the inverse of the price-to-earnings (P/E) ratio.

Enterprise Value: A measure of a company's total value that includes its market capitalization as well as short- and long-term debt and cash on its balance sheet.

Free Cash Flow (FCF): The amount of cash a company has remaining after expenses, debt service, capital expenditures, and dividends. High free cash flow typically suggests stronger company value.

Free-Cash-Flow Margin: The amount of free cash flow as a percentage of revenue. High FCF margin often denotes strong profitability.

Free-Cash-Flow Yield: Free cash flow per share divided by share price. A high FCF yield often represents a good investment opportunity, because investors would be paying a reasonable price for healthy cash earnings.

Full-Phase Average Performance: Calculates the (geometric) average performance of a sector in a particular phase of the business cycle and subtracts the performance of the broader equity market.

Median Monthly Difference: Calculates the difference in the monthly performance of a sector compared with the broader market, and then takes the midpoint of those observations.

Price-to-Book (P/B) Ratio: The ratio of a company's share price to reported accumulated profits and capital.

Price-to-Earnings (P/E) Ratio: The ratio of a company's current share price to its reported earnings. A forward P/E ratio typically uses an average of analysts' published earnings estimates for the next 12 months.

Price-to-Sales (P/S) Ratio: The ratio of a company's current share price to reported sales.

Relative Strength: The comparison of a security's performance relative to a benchmark, typically a market index.

Return on Equity (ROE): The amount, expressed as a percentage, earned on a company's common stock investment for a given period.

Risk Decomposition: A mathematical analysis that estimates the relative contribution of various sources of volatility.

Methodology

Strategist View: Our sector strategist, Denise Chisholm, tracks key indicators that have influenced the historical likelihood of outperformance of each sector. This historical probability analysis informs the Strategist Views.

Fundamentals: Sector rankings are based on equally weighting the following four fundamental factors: EBITDA growth, earnings growth, ROE, and FCF margin. However, we evaluate the financials and real estate sectors only on earnings growth and ROE because of differences in their business models and accounting standards.

Relative Strength: Compares the strength of a sector versus the S&P 500 index over a six-month period, with a one-month reversal on the latest month; identifying relative strength patterns can be a useful indicator of short-term sector performance.

Relative Valuations: Valuation metrics for each sector are relative to the S&P 500. Ratios compute the current relative valuation divided by the 10-year historical average relative valuation, eliminating the top 5% and bottom 5% values to reduce the effect of potential outliers. Sectors are then ranked by their weighted average ratios, weighted as follows: P/E: 37%; P/B: 21%; P/S: 21%; and FCF yield: 21%. However, the financials and real estate sectors are weighted as follows: P/E: 65% and P/B: 35%.

Appendix

Information presented herein is for discussion and illustrative purposes only and is not a recommendation or an offer or a solicitation to buy or sell any securities. Views expressed are as 6/30/23, based on the information available at that time, and may change based on market and other conditions. Unless otherwise noted, the opinions provided are those of the authors and not necessarily those of Fidelity Investments or its affiliates. Fidelity does not assume any duty to update any of the information.

Information provided in, and presentation of, this document are for informational and educational purposes only and are not a recommendation to take any particular action, or any action at all, nor an offer or solicitation to buy or sell any securities or services presented. It is not investment advice. Fidelity does not provide legal or tax advice.

References to specific investment themes are for illustrative purposes only and should not be construed as recommendations or investment advice. Investment decisions should be based on an individual's own goals, time horizon, and tolerance for risk.

This piece may contain assumptions that are "forward-looking statements," which are based on certain assumptions of future events. Actual events are difficult to predict and may differ from those assumed. There can be no assurance that forward-looking statements will materialize or that actual returns or results will not be materially different from those described here.

Past performance is no guarantee of future results.

Investing involves risk, including risk of loss.

All indexes are unmanaged. You cannot invest directly in an index. Index or benchmark performance presented in this document does not reflect the deduction of advisory fees, transaction charges, and other expenses, which would reduce performance.

Stock markets are volatile and can decline significantly in response to adverse issuer, political, regulatory, market, or economic developments.

Because of its narrow focus, sector investing tends to be more volatile than investments that diversify across many sectors and companies. Sector investing is also subject to the additional risks associated with its particular industry. The Energy sector is defined as companies whose businesses are dominated by either of the following activities: the construction or provision of oil rigs, drilling equipment, or other energy-related services and equipment, including seismic data collection; or the exploration, production, marketing, refining, and/or transportation of oil and gas products, coal, and consumable fuels. Financials: companies involved in activities such as banking, consumer finance, investment banking and brokerage, asset management, and insurance and investments.

The energy industries can be significantly affected by fluctuations in energy prices and supply and demand of energy fuels, energy conservation, the success of exploration projects, and tax and other government regulations.

The technology industries can be significantly affected by obsolescence of existing technology, short product cycles, falling prices and profits, competition from new market entrants, and general economic condition.

Index Definitions: The Russell 3000® Index is a market capitalization-weighted index designed to measure the performance of the 3,000 largest companies in the U.S. equity market.

The S&P 500® index is a market capitalization-weighted index of 500 common stocks chosen for market size, liquidity, and industry group representation to represent U.S. equity performance. S&P 500 is a registered service mark of Standard & Poor's Financial Services LLC. Sectors and industries are defined by the Global Industry Classification Standard (GICS).

The S&P 500 sector indexes include the standard GICS sectors that make up the S&P 500 index. The market capitalization of all S&P 500 sector indexes together comprises the market capitalization of the parent S&P 500 index; each member of the S&P 500 index is assigned to one (and only one) sector.

The S&P CoreLogic Case-Shiller U.S. National Home Price Index is a composite of single-family home price indexes for the nine U.S. Census divisions and is calculated monthly. It is included in the S&P CoreLogic Case-Shiller Home Price Index Series, which seeks to measure changes in the total value of all existing single-family housing stock.

Appendix

Sectors are defined as follows: **Communication Services:** companies that facilitate communication or provide access to entertainment content and other information through various types of media. **Consumer Discretionary:** companies that provide goods and services that people want but don't necessarily need, such as televisions, cars, and sporting goods; these businesses tend to be the most sensitive to economic cycles. **Consumer Staples:** companies that provide goods and services that people use on a daily basis, like food, household products, and personal-care products; these businesses tend to be less sensitive to economic cycles. **Energy:** companies whose businesses are dominated by either of the following activities: the construction or provision of oil rigs, drilling equipment, or other energy-related services and equipment, including seismic data collection; or the exploration, production, marketing, refining, and/or transportation of oil and gas products, coal, and consumable fuels. **Financials:** companies involved in activities such as banking, consumer finance, investment banking and brokerage, asset management, and insurance and investments. **Health Care:** companies in two main industry groups: health care equipment suppliers and manufacturers, and providers of health care services; and companies involved in the research, development, production, and marketing of pharmaceuticals and biotechnology products. **Industrials:** companies whose businesses manufacture and distribute capital goods, provide commercial services and supplies, or provide transportation services. **Materials**: companies that are engaged in a wide range of commodity-related manufacturing. **Real Estate:** companies in two main industry groups—real estate investment trusts (REITs), and real estate management and development companies. **Technology:** companies in technology software and services and technology hardware and equipment. **Utilities:** companies considered to be electric, gas, or water utilities, or companies that operate as independent producers and/or distributors of power.

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Section 1: 10-K (10-K)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

/X/ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2022

OR

/ / TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ___________ to ___________

Commission File Number	Exact name of registrant as specified in its charter, state of incorporation, address of principal executive offices, zip code telephone number	I.R.S. Employer Identification Number
1-16305	PUGET ENERGY, INC A Washington Corporation 355 110th Ave NE Bellevue, Washington 98004 (425) 454-6363	91-1969407
1-4393	PUGET SOUND ENERGY, INC. A Washington Corporation 355 110th Ave NE Bellevue, Washington 98004 (425) 454-6363	91-0374630

Securities registered pursuant to Section 12(b) of the Act: *None*

Title of Each Class	Trading Symbol	Name of Each Exchange on Which Registered
N/A	N/A	N/A

Securities registered pursuant to Section 12(g) of the Act: *None*

Title of Each Class	Trading Symbol	Name of Each Exchange on Which Registered
N/A	N/A	N/A

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Puget Energy, Inc.	Yes / /	No /X/	Puget Sound Energy, Inc.	Yes / /	No /X/

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Puget Energy, Inc.	Yes / /	No /X/	Puget Sound Energy, Inc.	Yes / /	No /X/

Indicate by check mark whether the registrants: (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Puget Energy, Inc.	Yes /X/	No / /	Puget Sound Energy, Inc.	Yes /X/	No / /

Indicate by check mark whether the registrants have submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Puget Energy, Inc.	Yes /X/	No / /	Puget Sound Energy, Inc.	Yes /X/	No / /

Indicate by check mark whether registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Puget Energy, Inc.	Large accelerated filer	/ /	Accelerated filer	/ /	Non-accelerated Filer	/X/	Smaller reporting company	/ /	Emerging growth company / /
Puget Sound Energy, Inc.	Large accelerated filer	/ /	Accelerated filer	/ /	Non-accelerated Filer	/X/	Smaller reporting company	/ /	Emerging growth company / /

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. / /

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.

Puget Energy, Inc.	Yes /X/	No / /	Puget Sound Energy, Inc.	Yes /X/	No / /

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.

Puget Energy, Inc.	Yes / /	No /X/	Puget Sound Energy, Inc.	Yes / /	No /X/

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b).

Puget Energy, Inc.	Yes / /	No /X/	Puget Sound Energy, Inc.	Yes / /	No /X/

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Puget Energy, Inc.	Yes / /	No /X/	Puget Sound Energy, Inc.	Yes / /	No /X/

As of February 6, 2009, all of the outstanding shares of voting stock of Puget Energy, Inc. are held by Puget Equico LLC, an indirect wholly-owned subsidiary of Puget Holdings LLC.

All of the outstanding shares of voting stock of Puget Sound Energy, Inc. are held by Puget Energy, Inc.

This Report on Form 10-K is a combined report being filed separately by: Puget Energy, Inc. and Puget Sound Energy, Inc. Puget Sound Energy, Inc. makes no representation as to the information contained in this report relating to Puget Energy, Inc. and the subsidiaries of Puget Energy, Inc. other than Puget Sound Energy, Inc. and its subsidiaries.

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DEFINITIONS

AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement and Environmental Obligations
aMW	Average Megawatt
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
BPA	Bonneville Power Administration
Colstrip	Colstrip, Montana coal-fired steam electric generation facility
Dth	Dekatherm (one Dth is equal to one MMBtu)
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortization
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	U.S. Generally Accepted Accounting Principles
GHG	Greenhouse Gases
GRC	General Rate Case
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ISDA	International Swaps and Derivatives Association
kW	Kilowatt (one kW equals one thousand watts)
kWh	Kilowatt Hour (one kWh equals one thousand watt hours)
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
LTI Plan	Long-Term Incentive Plan
MMBtus	One Million British Thermal Units
MW	Megawatt (one MW equals one thousand kW)
MWh	Megawatt Hour (one MWh equals one thousand kWh)
NAESB	North American Energy Standards Board
NOAA	National Oceanic and Atmospheric Administration
NPNS	Normal Purchase Normal Sale
NWP	Northwest Pipeline, LLC
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
PCA	Power Cost Adjustment
PCORC	Power Cost Only Rate Case
PGA	Purchased Gas Adjustment
PLR	Private Letter Ruling
PSE	Puget Sound Energy, Inc.
PTC	Production Tax Credit
PUDs	Washington Public Utility Districts
Puget Energy	Puget Energy, Inc.
Puget Equico	Puget Equico, LLC
Puget Holdings	Puget Holdings, LLC

SEC	United States Securities and Exchange Commission
SERP	Supplemental Executive Retirement Plan
SOFR	Secured Overnight Financing Rate
VIE	Variable Interest Entity
Washington Commission	Washington Utilities and Transportation Commission
WSPP	WSPP, Inc.

FORWARD-LOOKING STATEMENTS

Puget Energy and Puget Sound Energy, Inc. (PSE) include the following cautionary statements in this Form 10-K to make applicable and to take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by or on behalf of Puget Energy or PSE. This report includes forward-looking statements, which are statements of expectations, beliefs, plans, objectives and assumptions of future events or performance. Words or phrases such as "anticipates," "believes," "continues," "could," "estimates," "expects," "future," "intends," "may," "might," "plans," "potential," "predicts," "projects," "should," "will likely result," "will continue" or similar expressions are intended to identify certain of these forward-looking statements and may be included in discussion of, among other things, our anticipated operating or financial performance, business plans and prospects, planned capital expenditures and other future expectations. In particular, these include statements relating to future actions, business plans and prospects, future performance expenses, the outcome of contingencies, such as legal proceedings, government regulation and financial results.

Forward-looking statements reflect current expectations and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. There can be no assurance that Puget Energy's and PSE's expectations, beliefs or projections will be achieved or accomplished.

In addition to other factors and matters discussed elsewhere in this report, some important risks that could cause actual results or outcomes for Puget Energy and PSE to differ materially from past results and those discussed in the forward-looking statements include:

- Governmental policies and regulatory actions, including those of the Federal Energy Regulatory Commission (FERC) and the Washington Utilities and Transportation Commission (Washington Commission), that may affect our ability to recover costs and earn a reasonable return, including but not limited to disallowance or delays in the recovery of capital investments and operating costs and discretion over allowed return on investment;
- Changes in, adoption of and compliance with laws and regulations, including decisions and policies concerning the environment, climate change, greenhouse gas or other emissions or by products of electric generation (including coal ash or other substances) or distribution of natural gas, natural resources, and fish and wildlife (including the Endangered Species Act) as well as the risk of litigation arising from such matters, whether involving public or private claimants or regulatory investigative or enforcement measures;
- Changes in tax law, related regulations or differing interpretation, or enforcement of applicable law by the Internal Revenue Service (IRS) or other taxing jurisdiction; and PSE's ability to recover costs in a timely manner arising from such changes;
- Inability to realize deferred tax assets and use production tax credits (PTCs) due to insufficient future taxable income;
- Accidents or natural disasters, such as hurricanes, windstorms, earthquakes, floods, fires, extreme weather conditions, landslides, and other acts of God, terrorism, asset-based or cyber-based attacks, pandemic or similar significant events, which can interrupt service and lead to lost revenue, cause temporary supply disruptions and/or price spikes in the cost of fuel and raw materials and impose extraordinary costs;
- The impact of widespread health developments, including the global Coronavirus Disease 2019 (COVID-19) pandemic, and responses to such developments (such as voluntary and mandatory quarantines, government stay at home orders, restrictions on travel, commercial, social and other activities, and the impact of vaccination mandates on employee and vendor staffing levels) could materially and adversely affect, among other things, electric and natural gas demand, customers' ability to pay, supply chains, availability of skilled work-force, contract counterparties, liquidity and financial markets;
- Commodity price risks associated with procuring natural gas and power in wholesale markets from creditworthy counterparties;
- Wholesale market disruption, which may result in a deterioration of market liquidity, increase the risk of counterparty default, affect the regulatory and legislative process in unpredictable ways, negatively affect wholesale energy prices and/or impede PSE's ability to manage its energy portfolio risks and procure energy supply, affect the availability and access to capital and credit markets and/or impact delivery of energy to PSE from its suppliers;
- Financial difficulties of other energy companies and related events, which may affect the regulatory and legislative process in unpredictable ways, adversely affect the availability of and access to capital and credit markets and/or impact delivery of energy to PSE from its suppliers;
- The effect of wholesale market structures (including, but not limited to, regional market designs or transmission organizations) or other related federal initiatives;
- PSE electric or natural gas distribution system failure, blackouts or large curtailments of transmission systems (whether PSE's or others'), or failure of the interstate natural gas pipeline delivering to PSE's system, all of which can affect PSE's ability to deliver power or natural gas to its customers and generating facilities;
- Electric plant generation and transmission system outages, which can have an adverse impact on PSE's expenses with respect to repair costs, added costs to replace energy or higher costs associated with dispatching a more expensive generation resource;

- The ability to restart generation following a regional transmission disruption;

- The ability of a natural gas or electric plant to operate as intended;
- PSE's resource adequacy needs to meet the Clean Energy Transformation Act (CETA) and the Climate Commitment Act (CCA) requirements, through a combination of owned or contracted resources, may significantly increase purchased power and gas costs if pricing pressures and supply constraints on resource acquisitions increase;
- Changes in climate, weather conditions, or sustained extreme weather events in the Pacific Northwest, which could have effects on customer usage and PSE's revenue and expenses;
- Regional or national weather, which could impact PSE's ability to procure adequate supplies of natural gas, fuel or purchased power to serve its customers and the cost of procuring such supplies;
- Variable hydrological conditions, which can impact streamflow and PSE's ability to generate electricity from hydroelectric facilities;
- Variable wind conditions, which can impact PSE's ability to generate electricity from the wind facilities;
- The ability to renew contracts for electric and natural gas supply and the price of renewal;
- Industrial, commercial and residential growth and demographic patterns in the service territories of PSE;
- General economic conditions in the Pacific Northwest, such as inflation, which may impact customer consumption or affect PSE's accounts receivable;
- The loss of significant customers, changes in the business of significant customers or the condemnation of PSE's facilities as a result of municipalization or other government action or negotiated settlement, which may result in changes in demand for PSE's services;
- The failure of information systems or the failure to secure information system data, which may impact the operations and cost of PSE's customer service, generation, distribution and transmission;
- Opposition and social activism that may hinder PSE's ability to perform work or construct infrastructure;
- Capital market conditions, including changes in the availability of capital and interest rate fluctuations;
- Employee workforce factors including strikes; work stoppages; retirements; absences due to pandemics, accidents, natural disasters or other significant, unforeseeable events; availability of qualified employees or the loss of a key executive;
- The ability to obtain insurance coverage, the availability of insurance for certain specific losses, and the cost of such insurance;
- Changes in Puget Energy's or PSE's credit ratings, which may have an adverse impact on the availability and cost of capital for Puget Energy or PSE generally;
- Deteriorating values of the equity, fixed income and other markets which could significantly impact the value of investments of PSE's retirement plan, post-retirement medical benefit plan trusts and the funding of obligations thereunder; and
- Recent laws proposed or passed by various municipalities in PSE's service territory, including Seattle, which seek to reduce or eliminate the use of natural gas in various contexts, such as for space, cooking, and water heating in new commercial and multifamily buildings, which in turn may impact operations due to costs and delays from incremental permitting and other requirements that are outside PSE's control.

Any forward-looking statement speaks only as of the date on which such statement is made and, except as required by law, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. For further information, see the reports on Form 10-Q and current reports on Form 8-K.

PART I

ITEM 1. BUSINESS

General

Puget Energy is an energy services holding company incorporated in the state of Washington in 1999. Substantially all of its operations are conducted through its regulated subsidiary, Puget Sound Energy, Inc. (PSE), a utility company. Puget Energy also has a wholly-owned, non-regulated subsidiary, Puget LNG, LLC (Puget LNG), which was formed in 2016 and has the sole purpose of owning, developing and financing the non-regulated activity of a liquefied natural gas (LNG) facility at the Port of Tacoma, Washington.

Puget Energy is owned through a holding company structure by Puget Holdings, LLC (Puget Holdings). All of Puget Energy's common stock is indirectly owned by Puget Holdings. Puget Holdings is owned by a consortium of long-term infrastructure investors including the British Columbia Investment Management Corporation (BCIMC), the Alberta Investment Management Corporation (AIMCo), Ontario Municipal Employee Retirement System (OMERS), PGGM Vermogensbeheer B.V., Macquarie Washington Clean Energy Investment, L.P., and Ontario Teachers' Pension Plan Board. Puget Energy and PSE are collectively referred to herein as "the Company."

Corporate Strategy

Puget Energy is the direct parent company of PSE, the oldest and largest electric and natural gas utility headquartered in the state of Washington, primarily engaged in the business of electric transmission, distribution and generation and natural gas distribution. Puget Energy's business strategy is to generate stable earnings and cash flow by offering reliable electric and natural gas service in a cost-effective manner through PSE, and be the clean energy provider of choice for its customers.

Customers and Revenue Overview

PSE is a public utility incorporated in the state of Washington in 1960. PSE furnishes electric and natural gas service in a territory covering approximately 6,000 square miles, principally in the Puget Sound region.

The following table presents the number of PSE customers for electric and natural gas as of December 31, 2022 and 2021:

Customer Count by Class	December 31, 2022	December 31, 2021	Percent	December 31, 2022	December 31, 2021	Percent
(in thousands)	Electric		Change	Natural Gas		Change
Residential	1,072	1,059	1.2%	813	806	0.9%
Commercial	134	133	0.8%	57	57	—%
Industrial	3	3	—%	2	2	—%
Other	8	8	—%	—	—	—%
Total[1]	1,217	1,203	1.2%	872	865	0.8%

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[1] *At December 31, 2022, and 2021, approximately 423,382 and 419,437 customers purchased both electricity and natural gas from PSE, respectively.*

PSE's revenues and associated expenses are not generated evenly throughout the year, primarily due to seasonal weather patterns, varying wholesale prices for electricity and the amount of hydroelectric energy supplies available to PSE, which make quarter-to-quarter comparisons difficult. Weather conditions in PSE's service territory have an impact on customer energy usage and affect PSE's billed revenue and energy supply expenses. While both PSE's electric and natural gas sales are generally greatest during winter months, variations in energy usage by customers occur from season to season and also month to month within a season, primarily as result of weather conditions. PSE normally experiences its highest retail energy sales, and corresponding higher power costs, during the winter heating season in the first and fourth quarters of the year and its lowest sales and corresponding lower power costs in the third quarter of the year. While fluctuations in weather conditions will continue to affect PSE's billed revenue and energy supply expenses from month to month, PSE's decoupling mechanisms for electric and natural gas operations are expected to normalize the impact of weather on operating revenue and net income.

Under the decoupling mechanism, the Washington Commission allows PSE to record a monthly adjustment to its electric and natural gas operating revenues related to electric transmission and distribution, natural gas operations and general administrative costs from residential, commercial and industrial customers. For additional information, see Business, "Regulation and Rates" included in Item 1 of this report and Note 4, "Regulation and Rates" to the consolidated financial statements included in Item 8 of this report.

Capital Expenditures

The following tables present PSE's capital expenditures for the five-year period ended December 31, 2022, and gross utility plant by category and percentages as of December 31, 2022:

Utility Plant Additions/Retirements 5-Year Total	2018 - 2022		
(Dollars in Thousands)	Electric	Natural Gas	Common
Additions	$ 1,876,770	$ 1,237,089	$ 696,279
Retirements	(883,625)	(99,768)	(357,513)
Net utility plant	$ 993,145	$ 1,137,321	$ 338,766

Utility Plant Balance	December 31, 2022					
(Dollars in Thousands)	Electric		Natural Gas		Common	
Distribution	$ 4,760,017	41.9%	$ 4,719,214	91.3%	$ —	—%
Generation	4,060,463	35.8	3,239	0.1	—	—
Transmission	1,683,737	14.8	—	—	—	—
General plant & other	851,760	7.5	444,746	8.6	1,087,927	100.0
Total (excluding CWIP)	$ 11,355,977	100.0%	$ 5,167,199	100.0%	$ 1,087,927	100.0%

Corporate Location

PSE’s and Puget Energy's principal executive offices are located at 355 110th Ave NE, Bellevue, Washington 98004 and the telephone number is (425) 454-6363.

Available Information

The Company’s reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available or may be accessed free of charge at the Company's website, www.pugetenergy.com. The Securities and Exchange Commission (SEC) maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC and information may also be obtained via the SEC Internet website at www.sec.gov.

Regulation and Rates

PSE is subject to the regulatory authority of the following: (i) the FERC with respect to the transmission of electricity, the sale of electricity at wholesale, accounting and certain other matters; and (ii) the Washington Commission as to retail rates, accounting, the issuance of securities and certain other matters. PSE also must comply with mandatory electric system reliability standards developed by the North American Electric Reliability Corporation (NERC), the electric reliability organization certified by the FERC, whose standards are enforced by the Western Electricity Coordinating Council (WECC) in PSE's operating territory.

Rate mechanisms include: (i) trackers that typically track specific costs during the previous twelve-month period and (ii) riders that project cost recovery during a forward-looking twelve-month period. Both allow recovery of expenditures outside the process of a full general rate case (GRC).

The following table shows PSE's rate filings for its trackers and riders and whether or not they are included in decoupling rates:

Rate Filings	Electric	Natural Gas
Baseline rates	Yes	Yes
Expedited rate filing rider	Yes	Yes
Power cost only rates mechanism	No	N/A
Federal incentive tracker	No	N/A
Low income rates tracker	No	No
Pipeline cost recovery mechanism tracker	N/A	No
Prior year decoupling deferral tracker	No	No
Property tax tracker	No	No
Renewable energy credit tracker	No	N/A
Residential exchange credits tracker	No	N/A
Conservation costs rider	No	No
Purchased gas adjustment rider	N/A	No

General Rate Case Filing

PSE filed a GRC which includes a three-year multiyear rate plan with the Washington Commission on January 31, 2022, requesting an overall increase in electric and natural gas rates of 13.6% and 13.0% respectively in 2023; 2.5% and 2.3%, respectively in 2024; and 1.2% and 1.8%, respectively, in 2025. PSE requested a return on equity of 9.9% in all three rate years. PSE requested an overall rate of return of 7.39% in 2023; 7.44% in 2024; and 7.49% in 2025. The filing requests recovery of forecasted plant additions through 2022 as required by Revised Code of Washington (RCW) 80.28.425 as well as forecasted plant additions through 2025, the final year of the multiyear rate plan. In August 2022, three separate partial multiparty settlement agreements were reached. For further details regarding the partial settlement agreements, see Management's Discussion and Analysis, "Regulation of PSE Rates and Recovery of PSE Costs" included in Item 7 of this report. On January 6, 2023, the Washington Commission approved PSE's natural gas rates with an overall increase of $70.8 million or 6.40% in 2023 and $19.5 million or 1.65% in 2024, with the effective date of January 7, 2023. Furthermore, on January 10, 2023, the Washington Commission approved PSE's electric rates with an overall increase of $247.0 million or 10.75% in 2023 and $33.1 million or 1.33% in 2024, with an effective date of January 11, 2023.

PSE filed a GRC with the Washington Commission on June 20, 2019, requesting an overall increase in electric and natural gas rates of 6.9% and 7.9% respectively. On July 8, 2020, the Washington Commission issued its order on PSE's 2019 GRC. The ruling provided for a weighted cost of capital of 7.39% or 6.8% after-tax, and a capital structure of 48.5% in common equity with a return on equity of 9.4%. The order also resulted in a combined net increase to electric of $29.5 million, or 1.6%, and to natural gas of $36.5 million, or 4.0%. However, the Washington Commission extended the amortization of certain regulatory assets, PSE's electric decoupling deferral, and PSE's PGA deferral to mitigate the impact of the rate increase in response to the economic uncertainty created by the COVID-19 pandemic. This reduced the electric revenue increase to approximately $0.9 million, or 0.05% and the natural gas increase to $1.3 million, or 0.2% and became effective October 15, 2020 and October 1, 2020, respectively.

In July 2021, PSE received a Private Letter Ruling (PLR) from the IRS which concluded that in the 2019 GRC the Washington Commission's methodology for reversing plant-related excess deferred income taxes was an impermissible methodology under the IRS normalization and consistency rules. The PLR required adjustments to PSE's rates to bring PSE back into compliance with IRS rules. In September 2021, the Washington Commission amended its order in accordance with the PLR. The annualized overall rate impact was an increase of $15.8 million, or 0.7%, for electric and $3.1 million, or 0.3%, for natural gas for a total of $18.9 million with rates effective October 1, 2021. This led to a combined annualized net increase to electric rates of $77.1

million, or 3.7%, an increase of $17.5 million above the $59.6 million granted in the revised final order. The order also led to a combined annualized net increase to natural gas rates of $45.3 million, or 5.9%, an increase of $2.4 million above the $42.9 million granted in the revised final order. The Washington Commission maintained adjustments that mitigated the impacts of the rate increases in response to the economic instability created by the COVID-19 pandemic, which reduced the electric revenue increase to approximately $48.3 million, or 2.3%, and the natural gas increase to $4.9 million, or 0.6%.

Power Cost Only Rate Case

A power cost only rate case (PCORC) is a limited-scope proceeding to reset power cost rates. In addition to providing the opportunity to reset all power costs, the PCORC proceeding also provides for timely review of new resource acquisition costs and inclusion of such costs in rates at the time the new resource goes into service. To achieve this objective, the Washington Commission is not required to but historically has used an expedited six-month PCORC decision timeline rather than the statutory 11-month timeline for a GRC. In the 2022 GRC settlement, which the Washington Commission accepted with conditions, PSE agreed not to file a PCORC during 2023 and 2024, the two-year rate plan agreed to in the GRC settlement. Per the 2022 GRC Final Order in Docket No. UE-220066, PCORC rates were set to zero as of January 11, 2023.

Revenue Decoupling Adjustment Mechanism

While fluctuations in weather conditions will continue to affect PSE's billed revenue and energy supply expenses from month to month, PSE's decoupling mechanisms assist in mitigating the impact of weather on operating revenue and net income. The Washington Commission has allowed PSE to record a monthly adjustment to its electric and natural gas operating revenues related to electric transmission and distribution, natural gas operations and general administrative costs and fixed production costs from most residential, commercial and industrial customers to mitigate the effects of abnormal weather, conservation impacts and changes in usage patterns per customer. As a result, these electric and natural gas revenues are recovered on a per customer basis regardless of actual consumption levels. PSE's energy supply costs, which are part of the power cost adjustment (PCA) and PGA mechanisms, are not included in the decoupling mechanism. The revenue recorded under the decoupling mechanisms will be affected by customer growth and not actual consumption except for fixed production costs, which are held at the level of cost from the most recent rate proceeding and are not impacted by customer growth. Following each calendar year, PSE will recover from, or refund to, customers the difference between allowed decoupling revenue and the corresponding actual revenue during the following May to April time period. For further details regarding decoupling filings, see Note 4, "Regulation and Rates" to the consolidated financial statements included in Item 8 of this report.

Electric Rate Filings

Colstrip Adjustment Rider

This schedule implements surcharges and/or credits to collect or pass back the costs incurred or benefits realized associated with Colstrip Power Plant Units 1 & 2 and 3 & 4 as authorized in Washington Commission Docket No. UE-220066. Beginning in 2026, only decommissioning and remediation related costs will be included in this Schedule in compliance with the CETA.

Energy Charge Credit Recovery Adjustment

This schedule implements a surcharge to recover certain costs incurred under the electric Schedule 139 Voluntary Long Term Renewable Energy Purchase Rider as authorized in Washington Commission Docket No. UE-220066. The surcharge in this schedule will be updated with each filing that revises the Schedule 139 Energy Charge Credit.

Rates Not Subject to Refund Rate Adjustment

The purpose of this schedule is to recover costs approved during a multiyear rate plan period that are not subject to refund and that are above the level of base rates set in the multiyear rate plan as authorized in Washington Commission Docket No. UE-220066.

Rates Subject to Refund Rate Adjustment

The purpose of this schedule is to charge customers the provisionally approved rates subject to refund approved in a multiyear rate plan, for property granted provisional approval for recovery as authorized in Washington Commission Docket No. UE-220066. PSE will file with the Washington Commission an annual review filing by March 31st each year.

Transportation Electrification Plan Adjustment Rider

This schedule implements surcharges to collect costs incurred associated with the implementation of the Company’s Transportation Electrification Plan, and specifically the products and services offered under Schedules 551, 552, 553, 554, 555, 556, 557, 558, 559 and 583.

Conservation Service Rider

The electric conservation rider collects revenue to cover the costs incurred in providing services and programs for conservation. Rates change annually on May 1 to collect the annual budget that started the prior January and to true-up for actual compared to forecast conservation expenditures from the prior year, as well as actual compared to the forecasted load set in rates.

Federal Incentive Tracker

The Federal Incentive Tracker passes through to customers the benefits associated with the wind-related treasury grants. The filing results in a credit back to customers for pass-back of treasury grant amortization and pass-through of interest and any related true-ups. The filing is adjusted annually for new federal benefits, actual versus forecast interest and to true-up for actual load being different than the forecasted load set in rates. Rates change annually on January 1.

Low Income Program

The Low Income Tracker Tariff recovers changes in costs for the low income bill payment assistance program (as approved in Washington Commission Docket No. UE-011570). The annual filing requests these changes through the existing low income program funding mechanism previously approved by the Washington Commission. The mechanism allows PSE to periodically adjust its electric and natural gas rates to reflect changes in actual sales and costs. Rates change annually on October 1. Included in the electric rate effective October 1, 2022, is the recovery of $25.6 million from the COVID-19 bill assistance program established in Docket No. U-200281 and deferred under the accounting petition approved in Docket No. UE-200780.

Power Cost Adjustment Clause

PSE updated its Schedule 95 rates in the Power Cost Adjustment Clause tariff to reflect the transition fee as required by Section 12 of the Special Contract, a non-prescribed commercial/industrial rate contract. Additionally, Schedule 95 rates also include portions of fixed power cost adjustments per the allowed decoupling rate re-allocation resulting from a Special Contract customer becoming a transportation customer as well as small variable power cost adjustments.

Power Cost Adjustment Mechanism

PSE currently has a PCA mechanism that provides for the deferral of power costs that vary from the “power cost baseline” level of power costs. The “power cost baseline” levels are set, in part, based on normalized assumptions about weather and hydroelectric conditions. Excess power costs or savings are apportioned between PSE and its customers pursuant to the graduated scale set forth in the PCA mechanism and will trigger a surcharge or refund when the cumulative deferral trigger is reached.

Effective January 1, 2017, the following graduated scale is used in the PCA mechanism:

	Company's Share		Customers’ Share	
Annual Power Cost Variability	Over	Under	Over	Under
Over or Under Collected by up to $17 million	100%	100%	—%	—%
Over or Under Collected by between $17 million - $40 million	35	50	65	50
Over or Under Collected beyond $40 + million	10	10	90	90

Property Tax Tracker

The purpose of the property tax tracker is to pass through the cost of all property taxes incurred by the Company. The mechanism acts as a tracker rate schedule and collects the total amount of property taxes assessed. The tracker is adjusted each year in May based on that year's assessed property taxes and true-up from the prior year.

Residential and Farm Energy Exchange Benefit

The residential exchange program passes through the residential exchange program benefits that PSE receives from the Bonneville Power Administration (BPA). Rates change biennially on October 1.

Natural Gas Rate Filings

Distribution Pipeline Provisional Recovery Adjustment

This schedule implements surcharges in order to defer the revenues associated with the provisional recovery of $30 million for the four miles of distribution pipe to support proper allocation of the investments in a later filing as authorized in Washington Commission Docket No. UG-220067.

Rates Not Subject to Refund Rate Adjustment

The purpose of this schedule is to recover costs approved during a multiyear rate plan period that are not subject to refund and that are above the level of base rates set in the multiyear rate plan as authorized in Washington Commission Docket No. UG-220067.

Rates Subject to Refund Rate Adjustment

The purpose of this schedule is to charge customers the provisionally approved rates subject to refund approved in a multiyear rate plan, for property granted provisional approval for recovery as authorized in Washington Commission Docket No. UG-220067.

Natural gas rate filings

Conservation Service Rider

The natural gas conservation rider collects revenue to cover the costs incurred in providing services and programs for conservation. Rates change annually on May 1 to collect the annual budget that started the prior January and to true-up for actual compared to forecast conservation expenditures from the prior year, as well as actual compared to the forecasted load set in rates.

Cost Recovery Mechanism for Pipeline Replacement

The purpose of the cost recovery mechanism (CRM) is to recover costs related to projects included in PSE's pipeline replacement program plan on file with the Washington Commission with the intended effect of enhancing the safety of the natural gas distribution system. Rates change annually on November 1. In its 2022 GRC, PSE requested and the Washington Commission approved the recovery of its natural gas CRM investments in the multiyear rate plan. Effective January 7, 2023 PSE will no longer use the CRM annual filing to recover these pipeline replacement program investments.

Property Tax Tracker

The purpose of the property tax tracker mechanism is to pass through the cost of all property taxes incurred by the Company. The mechanism removed property taxes from general rates and included those costs for recovery in an adjusting tariff rate. After the implementation, the mechanism acts as a tracker rate schedule and collects the total amount of property taxes assessed. The tracker is adjusted each year in May based on that year's assessed property taxes and true-up from the prior year.

Purchased Gas Adjustment

PSE has a PGA mechanism that allows PSE to recover expected natural gas supply and transportation costs and defer, as a receivable or liability, any natural gas supply and transportation costs that exceed or fall short of this expected natural gas cost amount in PGA mechanism rates, including accrued interest. PSE is authorized by the Washington Commission to accrue carrying costs on PGA receivable and payable balances. A receivable or payable balance in the PGA mechanism reflects an under recovery or over recovery, respectively, of natural gas cost through the PGA mechanism. Rates typically change annually on November 1, although out-of-cycle rate changes are allowed at other times of the year if needed.

For additional information on electric and natural gas rates, see Management's Discussion and Analysis, "Regulation of PSE Rates and Recovery of PSE Costs" included in Item 7 of this report.

ELECTRIC UTILITY OPERATING STATISTICS

	Year Ended December 31,		
	2022	2021	2020
Generation and purchased power, MWh			
Company-controlled resources	11,198,936	12,949,384	11,700,918
Contracted resources	10,422,069	8,624,183	8,237,394
Non-firm energy purchased	4,922,194	4,491,714	4,916,761
Total generation and purchased power	26,543,199	26,065,281	24,855,073
Less: losses and Company use	(1,318,609)	(1,481,152)	(1,611,563)
Total energy sales, MWh	25,224,590	24,584,129	23,243,510
Electric energy sales, MWh			
Residential	11,753,057	11,479,045	10,976,068
Commercial	8,677,178	8,402,057	7,942,292
Industrial	1,113,909	1,082,718	1,095,916
Other customers	76,407	79,998	81,261
Total energy sales to customers	21,620,551	21,043,818	20,095,537
Sales to other utilities and marketers	3,604,039	3,540,311	3,147,973
Total energy sales, MWh	25,224,590	24,584,129	23,243,510
Transportation, including unbilled	2,300,711	2,246,244	2,220,372
Electric energy sales and transportation, MWh	27,525,301	26,830,373	25,463,882

Electric operating revenue by classes			
(Dollars in Thousands)			
Residential	$ 1,381,858	$ 1,318,320	$ 1,186,013
Commercial	981,170	902,928	791,898
Industrial	116,712	108,267	101,567
Other customers	18,734	18,067	18,182
Total operating revenue from customers	2,498,474	2,347,582	2,097,660
Transportation, including unbilled	22,353	19,987	19,682
Sales to other utilities and marketers	329,589	154,533	68,198
Decoupling revenue	(37,423)	(12,452)	49,632
Other decoupling revenue[1]	(12,067)	(17,506)	(27,053)
Miscellaneous operating revenue	160,531	179,479	111,297
Total electric operating revenue	$ 2,961,457	$ 2,671,623	$ 2,319,416
Number of customers served (average):			
Residential	1,065,508	1,053,027	1,039,596
Commercial	133,521	132,581	130,924
Industrial	3,222	3,267	3,289
Other	8,047	7,886	7,668
Transportation	104	98	100
Total customers	1,210,402	1,196,859	1,181,577

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1. *Includes decoupling cash collections, rate of return excess earnings, and decoupling 24-month revenue reserve.*

ELECTRIC UTILITY OPERATING STATISTICS (Continued)

	Year Ended December 31,		
	2022	2021	2020
Average kWh used per customer:			
Residential	11,030	10,901	10,558
Commercial	64,987	63,373	60,663
Industrial	345,720	331,410	333,206
Other	9,495	10,144	10,597
Average revenue per customer:			
Residential	$ 1,297	$ 1,252	$ 1,141
Commercial	7,348	6,810	6,049
Industrial	36,223	33,140	30,881
Other	2,328	2,291	2,371
Average retail revenue per kWh sold:			
Residential	$ 0.1176	$ 0.1148	$ 0.1081
Commercial	0.1131	0.1075	0.0997
Industrial	0.1048	0.1000	0.0927
Other	0.2452	0.2258	0.2237
Average retail revenue per kWh sold	$ 0.1156	$ 0.1116	$ 0.1044
Heating degree days	4,715	4,471	4,122
Percent of normal - NOAA[1] 30-year average	105.2 %	99.2 %	87.8 %
Load factor[2]	58.7 %	59.7 %	62.1 %

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1. *National Oceanic and Atmospheric Administration (NOAA).*
2. *Average megawatt (aMW) usage by customers divided by their maximum usage.*

Electric Supply

At December 31, 2022, PSE's electric power resources, which include company-owned or controlled resources as well as those under long-term contract, had a total capacity of approximately 6,565 megawatts (MW). In order to meet an extreme winter peak load, PSE may supplement its electric power resources with winter-peaking call options and other instruments. When it is more economical for PSE to purchase power than to operate its own generation facilities, PSE will purchase spot market energy when sufficient transmission capacity is available.

The following table shows PSE's electric energy supply resources and energy production for the years ended December 31, 2022, and 2021:

	Peak Power Resources At December 31,				Energy Production At December 31,			
	2022		2021		2022		2021	
	MW	%	MW	%	MWh	%	MWh	%
Purchased resources:								
Columbia River PUD contracts[1]	856	13.0%	681	14.2%	4,351,894	16.4%	3,458,996	13.3%
Other hydroelectric	99	1.5	111	2.3	497,229	1.9	529,239	2.0
Other producers	1,352	20.6	468	9.7	4,224,027	15.9	2,863,684	10.9
Wind/solar	902	13.7	193	4.0	1,419,839	5.3	934,634	3.6
Biomass	17	0.3	17	0.4	83,814	0.3	126,931	0.5
Short-term wholesale energy purchases	N/A	—	N/A	—	4,767,460	18.0	5,202,413	20.0
Total purchased	3,226	49.0%	1,470	30.6%	15,344,263	57.8%	13,115,897	50.3%
Company-controlled resources:								
Hydroelectric	263	4.0%	263	5.5%	758,615	2.9%	957,818	3.7%
Coal	370	5.6	370	7.7	2,726,665	10.3	2,576,702	9.9
Natural gas/oil	1,931	29.5	1,931	40.1	6,028,682	22.7	7,341,077	28.1
Wind/solar	773	11.8	773	16.1	1,684,974	6.3	2,073,787	8.0
Other[2]	2	—	2	—	—	—	—	—
Total company-controlled	3,339	51.0%	3,339	69.4%	11,198,936	42.2%	12,949,384	49.7%
Total resources	6,565	100.0%	4,809	100.0%	26,543,199	100.0%	26,065,281	100.0%

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1. *Net of 40 MW and 41 MW capacity delivered to Canada pursuant to the provisions of a treaty between Canada and the United States and Canadian Entitlement Allocation agreements as of December 31, 2022, and 2021, respectively.*

2. *It is estimated that the Glacier Battery Storage has delivered approximately 1,646.9 and 1,603.6 MWh as of December 31, 2022, and 2021, respectively.*

Company–Owned Electric Generation Resources

At December 31, 2022, PSE owns the following plants with an aggregate net generating capacity of 3,339 MW:

Plant Name	Plant Type	Net Maximum Capacity (MW)[1]	Year Installed
Colstrip Units 3 & 4 (25% interest)	Coal	370	1984 & 1986
Mint Farm	Natural gas combined cycle	320	2007; acquired 2008; upgraded 2017
Goldendale	Natural gas combined cycle	315	2004, acquired 2007, upgraded 2016
Frederickson Unit 1 (49.85% interest)	Natural gas combined cycle	136	2002; added duct firing 2005
Lower Snake River	Wind	343	2012
Wild Horse	Wind	273	2006 & 2009
Hopkins Ridge	Wind	157	2005 & 2008
Fredonia Units 1 & 2	Dual-fuel combustion turbines	207	1984
Frederickson Units 1 & 2	Dual-fuel combustion turbines	149	1981
Whitehorn Units 2 & 3	Dual-fuel combustion turbines	149	1981
Fredonia Units 3 & 4	Dual-fuel combustion turbines	107	2001
Ferndale	Natural gas co-generation	253	1994; acquired 2012
Encogen	Natural gas co-generation	165	1993; acquired 1999
Sumas	Natural gas co-generation	127	1993; acquired 2008
Upper Baker River	Hydroelectric	104	1959; unit 2 upgraded 1997, uprated 2021
Lower Baker River	Hydroelectric	105	1925: reconstructed 1960; upgraded 2001 and 2013
Snoqualmie Falls[2]	Hydroelectric	54	1898 to 1911 & 1957; rebuilt 2013
Crystal Mountain	Internal combustion	3	1969

Glacier Battery Storage	Lithium Iron Phosphate	2	2016
Total Net Capacity		3,339	

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1. *Net Maximum Capacity is the capacity a unit can sustain over a specified period of time when not restricted by ambient conditions or deratings, less the losses associated with auxiliary loads.*
2. *The FERC license authorizes the full 54.4 MW; however, the project's water right issued by the Washington State Department of Ecology limits flow to 2,500 cubic feet and therefore output to 47.7MW.*

Columbia River Electric Energy Supply Contracts

During 2022, approximately 16.4% of PSE’s energy supply was obtained through long-term contracts with three Washington Public Utility Districts (PUDs) that own and operate hydroelectric projects on the Columbia River (Mid-Columbia). PSE’s payments are not contingent upon the projects being operable.

For the year ended, December 31, 2022, PSE's portion of the power output of the PUDs’ projects are set forth below:

Project	Contract Expiration Year	License Expiration Year	Company’s Annual Share (Approximate) Percent of Output	MW Capacity
Chelan County PUD:				
Rock Island Project	2031	2029	30.0 %	187
Rocky Reach Project	2031	2052	30.0	390
Douglas County PUD:				
Wells Project	2028	2052	26.4	222
Grant County PUD:				
Priest Rapids Development	2052	2052	4.8	45
Wanapum Development	2052	2052	4.8	52
Total				896

Other Electric Supply, Exchange and Transmission Contracts and Agreements

PSE purchases electric energy under long-term firm purchased power contracts with other utilities and marketers in the Western region. PSE is generally not obligated to make payments under these contracts unless power is delivered. PSE also has an agreement with Pacific Gas & Electric Company (PG&E) for 300 MW of seasonal capacity exchange which, on November 14, 2022, PSE submitted a notice of termination with an effective date of December 31, 2027. During and since emerging from its 2001-2004 and 2019-2020 bankruptcy proceedings, PG&E delivered on the energy exchange contract and has continued to meet the exchange contract through its current bankruptcy proceedings.

PSE began participating in the Energy Imbalance Market (EIM) operated by the California Independent System Operator on October 1, 2016. PSE has committed up to 450 MW of existing BPA transmission for the EIM market. Participation has resulted in reduced costs for PSE customers of approximately $31.1 million in year ended December 31, 2022, enhanced system reliability, integration of variable energy resources, and geographic diversity of electricity demand and generation resources. The calculated benefits represent the annual cost savings of the EIM dispatch compared with a counter-factual dispatch without the EIM. Benefits can take the form of cost savings or revenues or their combination. Benefits include greenhouse gases (GHG) revenue, transfer revenues and flexible ramping revenues.

PSE has entered into multiple various-term transmission contracts with other utilities to integrate electric generation and contracted resources into PSE’s system. These transmission contracts require PSE to pay for transmission service based on the contracted MW level of demand, regardless of actual use. Other transmission agreements provide actual capacity ownership or capacity ownership rights. PSE’s annual charges under these agreements are also based on contracted MW volumes. Capacity on these agreements that is not committed to serve PSE’s load is available for sale to third parties. PSE also purchases short-term transmission services from a variety of providers, including the BPA.

In 2022, PSE had 5,007 MW and 595 MW of total transmission demand contracted with the BPA and other utilities, respectively. PSE’s remaining transmission capacity needs are met via PSE owned transmission assets.

Natural Gas Supply for Electric Customers

PSE purchases natural gas supplies for its power portfolio to meet electrical demand through gas-fired generation. Supplies range from long-term to daily agreements, as turbine fueling varies depending on market heat rates. Purchases are made from a diverse group of major and independent natural gas producers and marketers in the United States and Canada. PSE also enters into financial hedges to manage the cost of natural gas. PSE utilizes natural gas storage capacity and transportation that is dedicated to and paid for by the power portfolio to facilitate increased natural gas supply reliability and intra-day dispatch of PSE’s natural gas-fired generation resources.

The following table presents the volumes of natural gas for power inventory value as of December 31, 2022 and 2021:

	At December 31,	
	2022	2021
Natural gas volumes for power in storage at year end, therms (thousands):		
Jackson Prairie	5,450	5,237
Plymouth LNG (in LNG form)	1,223	1,552

Integrated Resource Plans, Resource Acquisition and Development

The 2021 Integrated Resource Plan marked a major departure from past Integrated Resource Plans (IRP) due in large part to the passage of CETA. The new electric progress report rules, Washington Administrative Code 480-100-625 Integrated Resource Plan Development and Timing, outlines the requirements for this report. The two-year progress report must be filed at least every two years after the utility files it's IRP. The final 2023 Electric Progress Report will be filed March 31, 2023. For the draft 2023 Progress Report, the cumulative capacity need by year, the capacity shortfalls and surpluses are:

	2023	2024	2025	2026	2027
Projected MW shortfall/(surplus)	(200)	174	465	1,336	1,848

PSE's current transmission portfolio includes approximately 1,500 MW of firm transmission rights that deliver energy from the Mid-Columbia trading hub to the PSE load center. Due to growing regional concerns pertaining to capacity within the short-term market, PSE will phase out its reliance on firm short-term market purchases by over 200 MW per year starting in 2024 until PSE reaches zero reliance by 2029. With the expected elimination of Colstrip units 3 & 4 from PSE's energy supply portfolio starting in 2026, which removes approximately 370 MW of capacity, and the expiration of PSE's 380 MW coal-transition contract with TransAlta when the Centralia coal plant is retired at the end of 2025, the projected capacity shortfall of 174 MW in 2024 increases to 1,336 MW and 1,848 MW by 2026 and 2027, respectively. The expected capacity needs reflect the mix of energy efficiency programs deemed cost effective in the 2023 Progress Report. As part of the Washington CETA, PSE must achieve sales with renewable or non-emitting resources of at least 80% by 2030 and 100% by 2045.

On February 10, 2023 the FERC approved a voluntary regional resource adequacy program that PSE plans to participate in along with other utilities in the Western United States and Canada. The program is intended to help the region anticipate its future power supply needs as natural gas-fired and coal power plants retire and are replaced by variable renewable energy resources such as wind and solar.

NATURAL GAS UTILITY OPERATING STATISTICS

	Year Ended December 31,		
	2022	2021	2020
Natural gas operating revenue by classes (Dollars in Thousands):			
Residential	$ 808,376	$ 722,002	$ 662,502
Commercial firm	324,743	270,708	232,306
Industrial firm	22,965	19,664	17,662
Interruptible	29,582	23,571	22,622
Total retail natural gas sales	1,185,666	1,035,945	935,092
Transportation services	20,381	20,104	17,296
Decoupling revenue	(4,008)	10,254	18,906
Other decoupling revenue[1]	(15,561)	(11,807)	(6,478)
Other	23,158	12,922	16,097
Total natural gas operating revenue	$ 1,209,636	$ 1,067,418	$ 980,913
Number of customers served (average):			
Residential	809,965	801,186	791,612
Commercial firm	56,824	56,477	56,303
Industrial firm	2,260	2,277	2,293
Interruptible	272	278	288
Transportation	211	220	224
Total customers	869,532	860,438	850,720
Natural gas volumes, therms (thousands):			

Residential	632,145	611,028	592,811
Commercial firm	294,879	270,022	250,611
Industrial firm	23,467	22,794	21,946
Interruptible	49,322	46,115	45,240
Total retail natural gas volumes, therms	999,813	949,959	910,608
Transportation volumes	219,059	219,805	212,330
Total volumes	1,218,872	1,169,764	1,122,938

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1. *Includes decoupling cash collections, rate of return excess earnings, and decoupling 24-month revenue reserve.*

NATURAL GAS UTILITY OPERATING STATISTICS (Continued)

	Year Ended December 31,		
	2022	2021	2020
Working natural gas volumes in storage at year end, therms (thousands):			
Jackson Prairie	79,463	82,080	78,016
Clay Basin	80,242	74,540	80,736
Tacoma LNG (in LNG form)	228	—	—
Gig Harbor LNG (in LNG form)	5	6	9
Average therms used per customer:			
Residential	780	763	749
Commercial firm	5,189	4,781	4,451
Industrial firm	10,384	10,011	9,571
Interruptible	181,331	165,881	157,083
Transportation	1,038,194	999,114	947,902
Average revenue per customer:			
Residential	$ 998	$ 901	$ 837
Commercial firm	5,715	4,793	4,126
Industrial firm	10,162	8,636	7,703
Interruptible	108,757	84,788	78,549
Transportation	96,592	91,382	77,214
Average revenue per therm sold:			
Residential	$ 1.279	$ 1.182	$ 1.118
Commercial firm	1.101	1.003	0.927
Industrial firm	0.979	0.863	0.805
Interruptible	0.600	0.511	0.500
Average retail revenue per therm sold	$ 1.186	$ 1.091	$ 1.027
Transportation	0.093	0.091	0.081
Heating degree days	4,715	4,471	4,122
Percent of normal - NOAA 30-year average	105.2 %	99.2 %	87.8 %

NATURAL GAS FOR NATURAL GAS CUSTOMERS AND ELECTRIC CUSTOMERS

Natural Gas Supply for Natural Gas Customers

PSE purchases a portfolio of natural gas supplies ranging from long-term firm to daily from a diverse group of major and independent natural gas producers and marketers in the United States and Canada (British Columbia and Alberta). PSE also enters into physical and financial hedges to manage volatility in the cost of natural gas. All of PSE's natural gas supply is ultimately transported through the facilities of Northwest Pipeline, LLC (NWP), the sole interstate pipeline delivering directly into PSE's service territory. Accordingly, delivery of natural gas supply to PSE's natural gas system is dependent upon the reliable operations of NWP.

For base load, peak management and supply reliability purposes, PSE supplements its firm natural gas supply portfolio by purchasing natural gas in periods of lower demand, injecting it into underground storage facilities and withdrawing it during periods of high demand or reduced supply. Underground storage facilities at Jackson Prairie in western Washington and at Clay Basin in Utah are used for this purpose. Clay Basin withdrawals are used to supplement purchases from the U.S. Rocky Mountain supply region, while Jackson Prairie provides incremental peak-day resources utilizing firm storage redelivery transportation capacity. Jackson Prairie is also used for daily balancing of load requirements on PSE's natural gas system. Peaking needs are also met by using PSE-owned natural gas held in PSE's Tacoma LNG peaking facility and the Gig Harbor satellite LNG peaking facility, both located within its distribution system; as well as interrupting service to customers on interruptible service rates, if necessary.

PSE expects to meet its firm peak-day requirements for residential, commercial and industrial markets through its firm natural gas purchase contracts, firm transportation capacity, firm storage capacity and other firm peaking resources. PSE believes it will be able to acquire incremental firm natural gas supply and transportation capacity to meet anticipated growth in the requirements of its firm customers for the foreseeable future.

PSE's firm natural gas supply portfolio has flexibility in its transportation arrangements to enable it to achieve savings when there are regional price differentials between natural gas supply basins. The geographic mix of suppliers and daily, monthly and annual take requirements permit some degree of flexibility in managing natural gas supplies during periods of lower demand to minimize costs. Natural gas is marketed outside of PSE's service territory (off-system sales) to optimize resources when on-system customer demand requirements permit and market economics are favorable; the resulting economics of these transactions are reflected in PSE's natural gas customer tariff rates through the PGA mechanism.

Natural Gas Storage Capacity

PSE holds storage capacity in the Jackson Prairie and Clay Basin underground natural gas storage facilities adjacent to NWP's pipeline to serve PSE's natural gas customers. The Jackson Prairie facility is operated and one-third owned by PSE, and is used primarily for intermediate peaking purposes due to its ability to deliver a large volume of natural gas in a short time period. Combined with capacity contracted from NWP's one-third stake in Jackson Prairie, PSE holds firm withdrawal capacity of 453,800 Dekatherm (Dth) per day, and over 9.8 million Dth of storage capacity at the Jackson Prairie facility. Of this total, PSE designates 397,100 Dth per day of the firm withdrawal capacity and over 9.2 million Dth of storage capacity to serve natural gas customers. The location of the Jackson Prairie facility in PSE's market area increases supply reliability and provides significant pipeline demand cost savings by reducing the amount of annual pipeline capacity required to meet peak-day natural gas requirements.

Of the remaining Jackson Prairie storage capacity, 56,700 Dth per day of firm withdrawal capacity and 640,600 Dth of storage capacity is currently designated to PSE's power portfolio, increasing natural gas supply reliability and facilitating intra-day dispatch of PSE's natural gas-fired generation resources.

The Clay Basin storage facility is a supply area storage facility that provides operational flexibility and price protection. PSE holds 12.9 million Dth of Clay Basin storage capacity and approximately 107,400 Dth per day of firm withdrawal capacity under two long-term contracts with remaining terms of five years and has rights to extend such agreements.

LNG and Propane-Air Resources

LNG and propane-air resources provide firm natural gas supply on short notice for short periods of time. Due to their typically high cost and slow cycle times, these resources are normally utilized as a last resort supply source in extreme peak-demand periods, typically during the coldest hours or days.

PSE holds a contract for LNG storage services of 241,700 Dth of PSE-owned natural gas at Plymouth, with a maximum daily deliverability of 70,500 Dth for use of the PSE generation fleet. PSE uses the Plymouth contract as an alternate supply source for natural gas required to serve PSE's generation fleet during peak periods on a daily or intra-day basis. In addition, PSE holds 15,000 Dth/day of firm pipeline capacity from Plymouth for the generation fleet. The balance of the LNG capacity is delivered using firm NWP pipeline transportation service previously acquired to serve PSE's generation fleet.

PSE owns and operates an LNG peaking facility in Gig Harbor, Washington, with total storage capacity of 10,600 Dth, which is capable of delivering 2,500 Dth of natural gas per day.

Tacoma LNG Facility

On February 1, 2022, the Tacoma LNG facility at the Port of Tacoma completed commissioning and commenced commercial operations. The Tacoma LNG facility provides peak-shaving services to PSE's natural gas customers, and provides LNG as fuel to transportation customers via Puget Energy's non-regulated subsidiary Puget LNG, particularly in the marine market at a lower cost due to the facility's scale. Pursuant to an order by the Washington Commission, PSE is allocated 43.0% of the capital and operating costs, consistent with the regulated portion of the Tacoma LNG facility, and Puget LNG is allocated the remaining 57.0% of the capital and operating costs. The portion of the Tacoma LNG facility allocated to PSE is subject to regulation by the Washington Commission. In December 2022, the Washington Commission approved and authorized PSE to seek recovery of costs related to the Tacoma LNG Facility concurrent with its 2023 PGA filing.

Natural Gas Transportation Capacity

PSE currently holds firm transportation capacity on pipelines owned by Cascade Natural Gas Company (CNGC), NWP, Gas Transmission Northwest (GTN), Nova Gas Transmission (NOVA), Foothills Pipe Lines (Foothills) and Enbridge Westcoast Energy (Westcoast). GTN, NOVA, and Foothills are all TC Energy Corporation companies. PSE pays fixed monthly demand charges for the right, but not the obligation, to transport specified quantities of natural gas from receipt points to delivery points on such pipelines each day for the term or terms of the applicable agreements.

PSE holds approximately 542,900 Dth per day of capacity for its natural gas customers on NWP that provides firm year-round delivery to PSE's service territory. In addition, PSE holds approximately 447,100 Dth per day of seasonal firm capacity on NWP to provide for delivery of natural gas stored at Jackson Prairie to natural gas customers. PSE holds approximately 202,900 Dth per day of firm transportation capacity on NWP to supply natural gas to its electric generating facilities. In addition, PSE holds over 34,200 Dth per day of seasonal firm capacity on NWP to provide for delivery of natural gas stored in Jackson Prairie for its electric generating facilities. PSE's firm transportation capacity contracts with NWP have remaining terms ranging from one to 22 years. However, PSE has either the unilateral right to extend the contracts under the contracts' current terms or the right of first refusal to extend such contracts under current FERC rules.

PSE's firm transportation capacity for its natural gas customers on Westcoast's pipeline is 135,800 Dth per day under various contracts, with remaining terms of two to three years. PSE has other firm transportation capacity on Westcoast's pipeline, which supplies the electric generating facilities, totaling 88,400 Dth per day, with remaining terms of three years and an option for PSE to renew its rights under the Westcoast contract. PSE has firm transportation capacity for its natural gas customers on NOVA and Foothills pipelines, each totaling approximately 79,000 Dth per day, with remaining terms of three years and an option for PSE to renew its rights on the capacity on NOVA and Foothills pipelines. PSE has other firm transportation capacity on NOVA and Foothills pipelines, which supplies the electric generating facilities, each totaling approximately 41,000 Dth per day, with remaining term of six years. PSE's firm transportation capacity for its natural gas customers on the GTN pipeline, totaling over 77,000 Dth per day, with remaining term of one year and PSE has a first right-of-refusal to extend such contracts under current FERC rules. PSE has other firm transportation capacity on GTN pipeline, which supplies the electric generating facilities, totaling 40,600 Dth per day, with remaining terms of one year. PSE holds 259,000 Dth per day of firm capacity on CNGC to connect generating facilities to the pipeline grid with remaining terms of one year.

Capacity Release

The FERC regulates the release of firm pipeline and storage capacity for facilities which fall under its jurisdiction. Capacity releases allow shippers to temporarily or permanently relinquish unutilized capacity to recover all or a portion of the cost of such capacity. The FERC allows capacity to be released through several methods including open bidding and pre-arrangement. PSE has acquired some firm pipeline and storage service through capacity release provisions to serve its growing service territory and electric generation portfolio. PSE also mitigates a portion of the demand charges related to unutilized storage and pipeline capacity through capacity release. Capacity release benefits derived from the natural gas customer portfolio are passed on to PSE's natural gas customers through the PGA mechanism.

Energy Efficiency

PSE is required under Washington state law to pursue all available electric conservation that is cost-effective, reliable and feasible. PSE offers programs designed to help new and existing residential, commercial and industrial customers use energy efficiently. PSE uses a variety of mechanisms including cost-effective financial incentives, information and technical services to enable customers to make energy efficient choices with respect to building design, equipment and building systems, appliance purchases and operating practices. PSE recovers the actual costs of its electric and natural gas energy efficiency

programs through rider mechanisms. However, the rider mechanisms do not provide assistance with gross margin erosion associated with reduced energy sales. To address this issue, PSE received approval in 2017 from the Washington Commission for continuation of electric and natural gas decoupling mechanisms, which mitigates gross margin erosion resulting from the Company's energy efficiency efforts. The decoupling mechanisms, as approved in 2022 GRC Final Order in Dockets No. UE-220066 and UG-220067 commenced January 7, 2023 for natural gas and January 11, 2023 for electric and will remain in place permanently until such time that PSE proposes and the Washington Commission approves to have them discontinued or modified.

Environment

PSE's operations, including generation, transmission, distribution, service and storage facilities, are subject to environmental laws and regulations by federal, state and local authorities. See below for the primary areas of environmental law that have the potential to most significantly impact PSE's operations and costs.

Air and Climate Change Protection

PSE owns numerous thermal generation facilities, including natural gas plants and an ownership percentage of Colstrip. All of the natural gas plants and Colstrip are governed by the Clean Air Act (CAA), and all have CAA Title V operating permits, which must be renewed every five years. This renewal process could result in additional costs to the plants. PSE continues to monitor the permit renewal process to determine the corresponding potential impact to the plants. These facilities also emit GHGs, and thus are also subject to any current or future GHG or climate change legislation or regulation including the Washington State Climate Commitment Act (CCA) and Washington State Clean Energy Transformation Act (CETA). The Colstrip plant represents PSE's most significant source of GHG emissions.

Species Protection

PSE owns hydroelectric plants, wind farms and numerous miles of above ground electric distribution and transmission lines that can be impacted by laws related to species protection. A number of species of fish have been listed as threatened or endangered under the Endangered Species Act (ESA), which influences hydroelectric operations, and may affect PSE operations, potentially representing cost exposure and operational constraints. Similarly, there are a number of avian and terrestrial species that have been listed as threatened or endangered under the ESA or are protected by the Migratory Bird Treaty Act or the Bald and Golden Eagle Protection Act. Prohibitions and permitting requirements set forth in these statutes and related regulations have the potential to influence operation of our wind farms and above ground transmission and distribution systems.

Remediation

PSE and its predecessors are responsible for environmental remediation at various sites. These include properties currently and formerly owned by PSE (or its predecessors), as well as third-party owned properties where hazardous substances were allegedly generated, transported or released. The primary cleanup laws to which PSE is subject include the Comprehensive Environmental Response, Compensation and Liability Act (federal) and, in Washington, the Model Toxics Control Act (state). PSE is also subject to applicable remediation laws in the state of Montana for its ownership interest in Colstrip. Under all of these laws, PSE may be subject to agency orders to carry out site remediation. These laws impose joint and several liability on any current or past owner or operator of a contaminated site, transporters, as well as any entity that generated and disposed of (or arranged for the disposal of) hazardous or other regulated substances at a contaminated site.

Hazardous and Solid Waste and Polychlorinated Biphenyl (PCB) Handling and Disposal

Related to certain operations, including power generation and transmission and distribution maintenance, PSE must handle and dispose of certain hazardous and solid wastes, including PCB waste from pre-1979 electrical equipment. These actions are regulated by the Solid Waste Disposal Act (as amended by the Resource Conservation and Recovery Act), the Toxic Substances Control Act (federal) and hazardous or dangerous waste regulations (state) that impose complex requirements on handling and disposing of regulated substances.

Water Protection

PSE facilities that discharge wastewater or storm water or store bulk petroleum products, and PSE construction projects above a certain threshold are governed by the Clean Water Act (federal and state), which includes the Oil Pollution Act amendments. This includes most generation facilities (and all of those with water discharges and some with bulk fuel storage), and many other facilities and construction projects depending on drainage, facility or construction activities, and chemical, petroleum and material storage.

Mercury Emissions

Mercury control equipment has been installed at Colstrip and has operated at a level that meets the current Montana requirement. Compliance, based on a rolling twelve-month average, was first confirmed in January 2011, and PSE continues to meet the requirement.

Siting New Facilities

In siting new generation, transmission, distribution or other related facilities in Washington, PSE is subject to the State Environmental Policy Act, and may be subject to the federal National Environmental Policy Act if there is a federal nexus, in addition to other possible state laws and local siting, critical area and zoning ordinances. Such facilities may also be subject to federal environmental regulations. These requirements may potentially require mitigation of environmental impacts as well as other measures that can add significant cost to new facilities.

Recent and Future Environmental Law and Regulation

Recent and future environmental laws and regulations have been and may be adopted at a federal, state or local level and may have a significant impact on the cost of PSE operations. PSE monitors legislative and regulatory developments for environmental issues with the potential to alter the operation and cost of our generation plants, transmission and distribution system, and other assets. Described below are the recent, pending and potential future environmental laws and regulations with the most significant potential impacts to PSE's operations and costs.

Climate Change and Greenhouse Gas Emissions

PSE implements both short-term measures and long-term strategies designed to manage GHG emissions in a scientifically sound and responsible fashion. The Company has worked closely with federal, state and local governments on deep decarbonization and the reduction and mitigation of GHG emissions, including passage of CETA and CCA. As a result, the Company announced a goal to be coal free by 2025, net zero carbon emissions for electric and natural gas operations (methane leaks from pipeline system) as well as electric supply by 2030. Further, the Company has an aspirational goal to be net zero by 2045 for natural gas sales and to go beyond reducing PSE's GHG footprint by helping Washington State address GHG emissions from the transportation sector by investing in electric vehicles and developing liquefied natural gas for maritime and commercial transportation. PSE also remains mindful of our customers' expectation of reliable, affordable service. The Company considers the cost of the decarbonization efforts to date, as well as future efforts, in its IRP process, and will continue to engage in climate and GHG policy development.

PSE's Greenhouse Gas Emission Reporting

PSE is required to submit, on an annual basis, a report of its GHG emissions to the state of Washington Department of Ecology including a report of emissions from all individual power plants emitting over 10,000 tons per year of GHGs and from certain natural gas distribution facilities and operations. Emissions exceeding 25,000 tons per year of GHGs from these sources must also be reported to the U.S. Environmental Protection Agency (EPA). Capital investments to monitor GHGs from the power plants and in the distribution system are not required at this time. Since 2002, PSE has voluntarily undertaken an annual inventory of its GHG emissions associated with PSE’s total electric retail load served from a supply portfolio of owned and purchased resources.

The most recent data indicate that PSE’s total GHG emissions (direct and indirect) from its electric supply portfolio in 2021 were 9.1 million metric tons of carbon dioxide equivalents. Approximately 27.5% of PSE’s total GHG emissions (approximately 2.5 million metric tons) are associated with PSE’s ownership and contractual interests in Colstrip. Compared to 2020, total emissions increased by 9.0%. This trend is due primarily to an increase in output from Colstrip Units 3 and 4 and an increase in output from the natural gas thermal fleet. PSE’s overall emissions strategy continues to demonstrate a concerted effort to manage customers’ needs with an appropriate balance of new renewable generation, existing generation owned and/or operated by PSE and significant energy efficiency efforts.

Executive Orders Addressing Environmental Issues

President Joseph Biden issued several executive orders in January 2021 that are likely to affect PSE’s environmental obligations. The executive orders revoked several existing executive orders and established new federal environmental mandates, including rejoining the Paris Agreement on climate change, which requires commitments to reduce GHG emissions, among other things.

Inflation Reduction Act

On August 16, 2022, the Inflation Reduction Act (IRA) was signed into public law. The IRA is intended to lower gasoline and electricity prices, increase energy security, and help consumers to afford emission-cutting technologies. In addition, the IRA will provide tax credits for clean electricity sources and renewable technologies, such as solar and wind. As of December 31, 2022, the IRA had no material financial impact on the Company, however the Company continues to assess the potential impacts of the legislation.

Federal Greenhouse Gas Rules: New and Existing Power Plants

The EPA sets rules that apply to both new and existing power plants regarding GHGs. In 2015, the EPA set a final rule regarding New Source Performance Standards (NSPS) for the control of carbon dioxide (CO_2) from new power plants that burn fossil fuels under section 111(b) of the CAA. New natural gas power plants can emit no more than 1,000 lbs. of CO_2/megawatt hour (MWh) which is achievable with the latest combined cycle technology. New coal power plants can emit no more than 1,400 lbs. of CO_2/MWh. Carbon Dioxide Capture and Sequestration (CCS) was reaffirmed by the EPA in this rule as the “best system of emission reductions” (BSER). In 2018, due to the high cost and limited geographic availability of CCS, EPA issued a proposed rule that the BSER for newly constructed coal-fired units is the most efficient demonstrated steam cycle in combination with the best operating practices, but did not take action on a final rule nor has EPA proposed to amend the NSPS. In January 2021, EPA issued a framework for determining when standards are appropriate for GHG emissions from stationary source categories under CAA section 111(b)(1)(A).

In August 2015, the EPA issued a final rule under Section 111(d) of the CAA, referred to as the Clean Power Plan (CPP), to regulate GHG emissions from existing power plants. The proposed rule includes state-specific goals and guidelines for states to develop plans for meeting these goals.

In June 2019, the EPA repealed the CPP rule and finalized the Affordable Clean Energy (ACE) rule, pursuant to Section 111(d) of the Clean Air Act as a CPP rule replacement. The ACE rule established emission guidelines for states to develop plans to address GHG emissions from existing coal-fired plants. On January 19, 2021 the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued an opinion vacating the ACE rule and remanding the rule back to the Agency for further consideration consistent with its opinion, after finding that the Agency had misinterpreted the CAA when adopting the ACE rule. In February 2021, the EPA issued a memorandum notifying states that it will not require the submittal of plans to the EPA under Section 111(d) because the court vacated the ACE rule without reinstating the CPP.

The Supreme Court granted review of the D.C. Circuit's decision related to EPA's authority to require generation shifting under the CPP in October 2021 (West Virginia v. EPA). PSE joined a coalition of utilities defending the vacatur of the ACE rule along with EPA, as well as, a coalition of states that includes Washington State. PSE cannot predict either the outcome of this case or its impact on the ACE rule or the CPP rule. Oral argument was held February 28, 2022, and the Supreme Court issued its decision on June 30, 2022, finding that EPA lacked clear congressional authorization to require generation shifting under Section 111(d), but remaining silent as to the appropriate scope of state compliance flexibilities. In response to this decision, on October 3, 2022, the D.C. Circuit recalled its partial mandate vacating the ACE Rule and granted a motion by EPA to hold pending challenges to the ACE Rule in abeyance while EPA develops a replacement rule. PSE cannot predict EPA’s timeline for issuing this replacement rule; however, in December 2022, EPA published proposed changes to the Section 111(d) implementing regulations, which will impact EPA's future promulgation of emissions guidelines, including the forthcoming 111(d) rule governing GHG emissions from existing electricity generating units. EPA has indicated that it intends to issue a final rule by April 2023.

Washington Climate Commitment Act

In 2021, the Washington Legislature adopted the CCA, which establishes a GHG emissions cap-and-invest program that caps GHG emissions beginning on January 1, 2023 and makes further reductions to the cap annually through 2050. The Washington Department of Ecology (WDOE) published final regulations to implement the program to implement the program on September 29, 2022, which became effective on October 30, 2022. In general, the program will require covered entities to obtain emission allowances or offset credits for covered emissions and the WDOE provides the annual allowance budget based on the cap. Allowances can be obtained through quarterly auctions, or bought and sold on a secondary market.

The CCA regulates PSE both as an electric utility and as a natural gas distribution utility. PSE is required to obtain emission allowances or offset credits for GHG emissions associated with electricity generated in or imported into the state to serve Washington State load, and all electricity generated by Washington State PSE facilities with total annual emissions exceeding 25,000 metric tons of carbon dioxide equivalent per year. As an electric utility subject to Washington's CETA, which is discussed below, PSE will receive emission allowances at no cost through 2050 for direct emissions associated with electricity used to serve Washington State load to mitigate impacts to ratepayers. PSE will also be required to obtain emission allowances for GHG emissions associated with natural gas supplied to customers and any natural gas system associated facilities with emissions that exceed 25,000 metric tons of carbon dioxide equivalent per year. PSE will receive some emission allowances at no cost; the amount will be based on a percentage of baseline emissions (determined from 2015 - 2019 natural gas system related emissions) that will decline to mitigate rate impacts to certain natural gas customers. Offset credit use is limited and the WDOE will reduce the cap proportionally for any offsets used. In the first compliance period, 2023-2026, participating entities can cover up to 5% of their emissions with offset credits, and can cover an additional 3% with credits from projects on federally recognized Tribal lands. In the second compliance period, 2027-2030, the general limit drops to 4%, with an additional 2% from projects on Tribal lands.

Washington Clean Energy Transformation Act

In May 2019, Washington State passed the CETA, which supports Washington's clean energy economy and transitioning to a clean, affordable, and reliable energy future. The CETA requires all electric utilities to eliminate coal-fired generation from their allocation of electricity by December 31, 2025; to be carbon-neutral by January 1, 2030 through a combination of non-emitting electric generation, renewable generation, and/or alternative compliance options; and makes it the state policy that, by 2045, 100% of electric generation and retail electricity sales will come from renewable or non-emitting resources. Clean energy implementation plans are required every four years from each investor-owned utility (IOU). The plan must propose interim targets for meeting the 2045 standard between 2030 and 2045 and describe an actionable plan that the IOU intends to pursue to meet the standard. The Washington Commission may approve, reject or recommend alterations to an IOU's plan. The Company intends to seek recovery of any costs associated with CETA through the regulatory process.

Regional Haze Rule

In January 2017, the EPA provided revisions to the Regional Haze Rule which were published in the Federal Register. Among other things, these revisions delayed new Regional Haze review from 2018 to 2021; however, the end date will remain 2028. In January 2018, the EPA announced that it would revisit certain aspects of these revisions and PSE is unable to predict the outcome. Challenges to the 2017 Regional Haze Revision Rule are being held in abeyance in the U.S. Court of Appeals for the D.C. Circuit, pending resolution of EPA's reconsideration of the rule.

Coal Combustion Residuals

In April 2015, the EPA published a final rule, effective October 2015, which regulates Coal Combustion Residuals (CCR) under the Resource Conservation and Recovery Act, Subtitle D. The CCR rule currently is self-implementing at a federal level, or can be implemented and enforced by a state. The rule addresses the risks from coal ash disposal, such as leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash containment structures by establishing technical design, operation and maintenance, closure and post closure care requirements for CCR landfills and surface impoundments, and corrective action requirements for any related leakage.

In addition to the EPA's CCR rule, the operator of Colstrip and the state of Montana in 2012 entered into an Administrative Order of Consent (AOC) that also addresses clean up and closure of CCR units at Colstrip. The CCR rule and the AOC require significant changes to the Company's Colstrip operations and those changes were reviewed by the Company and the plant operator in the second quarter of 2015. PSE had previously recognized a legal obligation under the EPA rules to dispose of ash material at Colstrip in 2003. Due to the CCR rule, additional disposal costs were added to the Asset Retirement and Environmental Obligations (ARO). In 2018, the D.C. Circuit Court of Appeals overturned certain provisions of the CCR rule in 2018 and remanded some of its provisions back to the EPA. As a result of that decision and certain other developments, EPA has continued to work on developing new rules regarding CCR, including establishing a presumptive date of April 11, 2021, for facilities to stop placing coal ash into unlined surface impoundments. In addition, the EPA has proposed a federal permitting program for coal ash disposal units along with the Water Infrastructure Improvement for the Nation Act (WIIN Act). The WIIN Act allows states to develop a state program for the regulation of CCR in lieu of the federal CCR rule, and also authorizes EPA to develop a federal permitting program. Currently, Montana has not applied for a state permit program, and EPA has not yet finalized a federal permitting program.

Human Capital Resources

PSE is committed to maintaining a work environment free of violence or harassment or discrimination of any kind, including harassment based on race, color, gender, sex, sexual orientation, age, religion, creed, national origin, marital status, veteran status or disability. Violence and threatening behavior are not tolerated by the Company, and employees are expected to treat one another with mutual respect and dignity. PSE complies with all federal, state, and local employment laws and prohibit unlawful discrimination in the recruiting, hiring, compensating, promoting, transferring, training, downgrading, terminating, laying off, or recalling of any person based upon race, religion, creed, color, national origin, age, sex, sexual orientation, gender identity, marital status, veteran or military status, the presence of a disability, or any other characteristic protected by law.

Additional information regarding the Company's human capital measures and objectives is contained in the Environmental, Social and Governance (ESG) report that can be found on the Company's website, www.pse.com. The information on the Company's website is not, and will not be deemed to be a part of this annual report on Form 10-K or incorporated into the Company's other filings with the SEC.

Employee Overview

At December 31, 2022, PSE had approximately 3,250 full-time equivalent employees. Approximately 970 PSE employees are represented by the International Brotherhood of Electrical Workers Union (IBEW) or the United Association of Plumbers and Pipefitters (UA). The UA contract was ratified effective December 2021, and will expire September 30, 2025. The IBEW contract was ratified effective April 1, 2020, and will expire March 31, 2026.

Puget Energy does not have any employees. PSE's employees provide services to Puget Energy and PSE charges for their salaries and benefits at cost.

Safety

Our safety objective is our foundation: Nobody gets hurt today so that we will feel safe and secure and able to perform at our best. When we're safe, we can achieve our people objective of being a great place to work, with engaged employees who live our values, embrace an ownership culture and are motivated to drive results for our company and our customers.

Our workplace safety program puts significant emphasis on education and training, delivering information by multiple means, including articles and videos. Topics cover not only safety around the equipment and conditions employees work in but also day-to-day issues such as ergonomics, mental health, and overall wellness. This ensures compliance with all federal Occupational Safety and Health Administration and Washington State Division of Occupational Safety and Health rules to ensure PSE provides and remains a safe and healthy working environment for all employees. PSE vehicles, equipment, and construction practices meet all applicable regulations and codes for worker and public safety. An executive-level steering committee oversees employee safety performance and programs. Policies are outlined in a comprehensive manual, which is maintained by PSE's Safety and Health Department. As a way of recognizing the importance of safety, the annual employee incentive is tied to performance on goals for safety.

Employee Benefits

To attract employees that meet the needs of the Company's skilled workforce, the Company offers employee benefits that are a component of the Company's total compensation package. Employee benefits include medical, health and dental insurance, long-term disability insurance, accidental death insurance, and our 401(k) plan. Non-represented and UA-represented employees hired on or after January 1, 2014 along with IBEW-represented employees hired on or after December 12, 2014, have access to the 401(k) plan. The two contribution sources from PSE are below:

- 401(k) Company Matching: non-represented, UA-represented and IBEW-represented employees PSE will match 100% on the first 3.0% of pay contributed and 50.0% on the next 3.0% of pay contributed, such that an employee who contributes 6.0% of pay will receive 4.5% of pay in company match. Company matching will be immediately vested.
- Company Contribution: UA-represented employees will receive an annual company contribution of 4.0% of eligible pay placed in the Cash Balance retirement plan. Non-represented and IBEW-represented employees will receive an annual company contribution of 4.0% of eligible pay, placed either in the Investment Plan 401(k) plan or in PSE's Cash Balance retirement plan. Non-represented and IBEW-represented employees will make a one-time election within 30 days of hire and direct that PSE put the 4.0% contribution either into the 401(k) plan or into an account in the Cash Balance retirement plan. The Company's 4.0% contribution will vest after three years of service. For additional details see Item 8 (for employees hired prior to January 1, 2014) and Item 11 of this report.

Employee Development

The Company offers development opportunities to employees. Some of the programs are:

- Employee wellness program: PSE maintains a wellness program that offers a wide range of resources and tools at little or no cost to employees and their families, including company sponsored wellness events and ongoing health and wellness communications. The PSE program also includes resources and tools that focus on mental health and wellbeing.
- Employee engagement: PSE has been conducting the Great Place to Work® survey since 2001 in an ongoing effort to create a culture that supports company values and enables PSE to do its best work on behalf of its customers and communities. The Company also conducts periodic pulse surveys to engage employees on relevant topics and provide them with opportunities to inform decisions.

- Professional development and tuition reimbursement: PSE provides its employees with tools and development resources to enhance their skills and careers at the Company. Employees are encouraged to discuss their professional development and identify interests during one-to-one discussions and annual performance reviews with their supervisors. Employees are provided with learning opportunities that support our diversity, equity and inclusion strategies and create a more inclusive culture. Leadership development is critical to PSE's success and we provide training and support to help leaders more effectively navigate and work in different ways including virtually or in a hybrid workplace. PSE has multiple training programs and modules designed to educate employees on an assortment of health and safety practices and certifications, corporate ethics and compliance, business management, employee relations, environmental awareness, community engagement, and regulatory compliance, and emergency preparation and response. PSE also offers employees a tuition reimbursement program for relevant education opportunities.
- Diversity, Equity and Inclusion (DEI): PSE is committed to being our customers' clean energy partner of choice and views DEI as an essential aspect of the Company's aspirations. As a result, PSE's employees are critical to creating an inclusive culture and the Company is committed to creating opportunities for engagement and learning from one another. PSE has nine active employee resource groups (ERGs) that are designed for inspiring engagement. ERGs are a benefit for its members and the Company as they create environments for integrating diverse perspectives, provide additional insight into how to solve problems, innovate, and meet customer needs. ERGs also help to build connections with local communities and business partners resulting in strengthened relationships. PSE joined a regional coalition of employers through the Washington Employers of Racial Equity (WERE) pledging our support for the Commitment to Progress. PSE also participates with other member companies of the Edison Electric Institute (EEI) to help shape DEI objectives. PSE currently is in the first phase, assess, of the 10-year process. The assess phase includes the following: (i) embedding the DEI assessment into functional work; (ii) gathering and analyzing data related to our community, customers, people and suppliers; (iii) gathering input from stakeholders; (iv) evaluating WERE and EEI commitments and DEI related efforts and (v) creating a task force to energize PSE ERGs to enhance employee engagement.

Executive Officers of the Registrants

The executive officers of Puget Energy as of February 23, 2023, are listed below along with their business experience during the past five years. Officers of Puget Energy are elected for one-year terms.

Name	Age	Offices
M. E. Kipp	55	President since August 2019; Chief Executive Officer since January 2020. President and Chief Executive Officer at El Paso Electric from May 2017 to August 2019; Chief Executive Officer at El Paso Electric from December 2015 to May 2017; President at El Paso Electric from September 2014 to December 2015
K. Hasan	52	Executive Vice President and Chief Financial Officer since August 2022; Senior Vice President and Chief Financial Officer from June 2021 to August 2022; Executive Vice President and Chief Financial Officer of CLECO Corporation from 2018 to June 2021; Chief Risk Officer and Vice President at AES Corporation from 2014 to 2018
L. Luebbe	55	Senior Vice President, Chief Sustainability Officer and General Counsel since December 1, 2022; Vice President Sustainability and Deputy General Counsel from March 2022 to November 2022; Assistant General Counsel and Director Environmental Services from 2005 to March 2022
S. W. Smith	37	Controller and Principal Accounting Officer since December 19, 2022; Manager, Revenue Requirements from September 2019 to December 2022; Manager, Energy and Derivatives Accounting from July 2018 to August 2019; Manager, Source to Pay Accounting at Nike, Inc. from August 2017 to July 2018

The executive officers of PSE as of February 23, 2023, are listed below along with their business experience during the past five years. Officers of PSE are elected for one-year terms.

Name	Age	Offices
M. E. Kipp	55	President since August 2019; Chief Executive Officer since January 2020. President and Chief Executive Officer at El Paso Electric from May 2017 to August 2019; Chief Executive Officer at El Paso Electric from December 2015 to May 2017
K. Hasan	52	Executive Vice President and Chief Financial Officer since August 2022; Senior Vice President and Chief Financial Officer from June 2021 to August 2022; Executive Vice President and Chief Financial Officer of CLECO Corporation from 2018 to June 2021; Chief Risk Officer and Vice President at AES Corporation from 2014 to 2018
M. F. Hopkins	57	Senior Vice President Shared Services and Chief Information Officer since March 2020; Vice President and Chief Information Officer from August 2013 to March 2020
L. Luebbe	55	Senior Vice President, Chief Sustainability Officer and General Counsel since December 1, 2022; Vice President Sustainability and Deputy General Counsel from March 2022 to November 2022; Assistant General Counsel and Director Environmental Services from 2005 to March 2022
A.W. Smith	58	Executive Vice President and Chief Operating Officer since July 2022. Senior Vice President, Electric Operations at Pacific Gas and Electric Company from May 2021 to July 2022. Senior Vice President, Grid Development at American Electric Power Service Company from 2015-2021
A.W. Wappler	58	Senior Vice President and Chief Customer Officer since November 2021. Vice President Customer Operations and Communications from 2016 to November 2021
S. W. Smith	37	Controller and Principal Accounting Officer since December 19, 2022; Manager, Revenue Requirements from September 2019 to December 2022; Manager, Energy and Derivatives Accounting from July 2018 to August 2019; Manager, Source to Pay Accounting at Nike, Inc. from August 2017 to July 2018

ITEM 1A. RISK FACTORS

The following risk factors, in addition to other factors and matters discussed elsewhere in this report, should be carefully considered. The risks and uncertainties described below are not the only risks and uncertainties that Puget Energy and PSE may face. Additional risks and uncertainties not presently known or currently deemed immaterial also may impair PSE's business operations. If any of the following risks actually occur, Puget Energy's and PSE's business, results of operations and financial conditions would suffer.

RISKS RELATING TO PSE's REGULATORY AND RATE-MAKING PROCEDURES

PSE's regulated utility business is subject to various federal and state regulations. PSE's regulatory risks include, but are not limited to, the items discussed below.

The actions of regulators can significantly affect PSE's earnings, liquidity and business activities. The rates that PSE is allowed to charge for its services are the single most important item influencing its financial position, results of operations and liquidity. PSE is highly regulated and the rates that it charges its wholesale and retail customers are determined by both the Washington Commission and the FERC.

PSE is also subject to the regulatory authority of the Washington Commission with respect to accounting, operations, the issuance of securities and certain other matters, and the regulatory authority of the FERC with respect to the transmission of electric energy, the sale of electric energy at the wholesale level, accounting and certain other matters. In addition, proceedings with the Washington Commission typically involve multiple stakeholder parties, including consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or decreasing rates. Policies and regulatory actions by these regulators could have a material impact on PSE's financial position, results of operations and liquidity.

PSE's recovery of costs is subject to regulatory review and its operating income may be adversely affected if its costs are disallowed. The Washington Commission determines the rates PSE may charge to its electric retail customers based, in part, on historic costs during a particular test year, adjusted for certain normalizing adjustments. Power costs on the other hand, are normalized for market, weather and hydrological conditions projected to occur during the applicable rate year, the ensuing twelve-month period after rates become effective. The Washington Commission determines the rates PSE may charge to its

natural gas customers based on historic costs during a particular test year. Natural gas costs are adjusted through the PGA mechanism, as discussed previously. If in a specific year PSE's costs are higher than the amounts used by the Washington Commission to determine the rates, revenue may not be sufficient to permit PSE to earn its allowed return or to cover its costs. In addition, the Washington Commission has the authority to determine what level of expense and investment is reasonable and prudent in providing electric and natural gas service. If the Washington Commission decides that part of PSE's costs do not meet the standard, those costs may be disallowed partially or entirely and not recovered in rates. For the aforementioned reasons, the rates authorized by the Washington Commission may not be sufficient to earn the allowed return or recover the costs incurred by PSE in a given period.

PSE is currently subject to a Washington Commission order that requires PSE to share its excess earnings above the authorized rate of return with customers. The Washington Commission previously approved an electric and natural gas decoupling mechanism for the recovery of its delivery-system and fixed production costs, along with a rate plan and earnings sharing mechanism that requires PSE and its customers to share in any earnings in excess of the authorized rate of return. The earnings test is done for each service (electric/natural gas) separately, so PSE would be obligated to share the earnings for one service exceeding the authorized rate of return, even if the other service did not exceed the authorized rate of return.

The PCA mechanism, by which variations in PSE's power costs are apportioned between PSE and its customers pursuant to a graduated scale, could result in significant increases in PSE's expenses if power costs are significantly higher than the baseline rate. PSE has a PCA mechanism that provides for recovery of power costs from customers or refunding of power cost savings to customers, as those costs vary from the "power cost baseline" level of power costs which are set, in part, based on normalized assumptions about weather and hydrological conditions. Excess power costs or power cost savings will be apportioned between PSE and its customers pursuant to the graduated scale set forth in the PCA mechanism and will trigger a surcharge or refund when the cumulative deferral trigger is reached. As a result, if power costs are significantly higher than the baseline rate, PSE's expenses could significantly increase.

RISKS RELATING TO PSE's OPERATION

PSE's cash flow and earnings could be adversely affected by potential high prices and volatile markets for purchased power, recurrence of low availability of hydroelectric resources, outages of its generating facilities or a failure to deliver on the part of its suppliers. The utility business involves many operating risks. If PSE's operating expenses, including the cost of purchased power and natural gas, significantly exceed the levels recovered from retail customers, its cash flow and earnings would be negatively affected. Factors which could cause PSE's purchased power and natural gas costs to be higher than anticipated include, but are not limited to, high prices in western wholesale markets during periods when PSE has insufficient energy resources to meet its energy supply needs and/or purchases in wholesale markets of high volumes of energy at prices above the amount recovered in retail rates due to:

- Below normal levels of generation by PSE-owned hydroelectric resources due to low streamflow conditions or precipitation;

- Extended outages of any of PSE-owned generating facilities or the transmission lines that deliver energy to load centers, or the effects of large-scale natural disasters on a substantial portion of distribution infrastructure; and
- Failure of a counterparty to deliver capacity or energy purchased by PSE.

PSE's electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs. PSE owns and operates coal, natural gas-fired, hydroelectric, and wind-powered generating facilities. Operation of electric generating facilities involves risks that can adversely affect energy output and efficiency levels or increase expenditures, including:

- Facility shutdowns due to a breakdown or failure of equipment or processes;
- Volatility in prices for fuel and fuel transportation;
- Disruptions in the delivery of fuel and lack of adequate inventories;
- Regulatory compliance obligations and related costs, including any required environmental remediation, and any new laws and regulations that necessitate significant investments in our generating facilities;
- Labor disputes;
- Operator error or safety related stoppages;
- Terrorist or other attacks (both cyber-based and/or asset-based); and

- Catastrophic events such as fires, explosions or acts of nature.

Cyber-attacks, including cyber-terrorism, foreign-state support cyber threats or other information technology security breaches, or information technology failures may disrupt business operations, increase costs, lead to the disclosure of confidential information and damage PSE's reputation. Security breaches of PSE's information technology infrastructure, including cyber-attacks and cyber-terrorism, or other failures of PSE's information technology infrastructure could lead to disruptions of PSE's production and distribution operations, and otherwise adversely impact PSE's ability to safely and effectively operate electric and natural gas systems and serve customers. In addition, an attack on or failure of information technology systems could result in the unauthorized release of customer, employee or Company data that is crucial to PSE's operational security or could adversely affect PSE's ability to deliver and collect on customer bills. Such security breaches of PSE's information technology infrastructure could adversely affect our operations and business reputation, diminish customer confidence, subject PSE to financial liability or increased regulation, expose PSE to fines or material legal claims and liability and adversely affect our financial results. PSE has implemented preventive, detective and remediation measures to manage these risks, and maintains cyber risk insurance to mitigate the effects of these events. Nevertheless, these may not effectively protect all of PSE's systems all of the time. To the extent that the occurrence of any of these cyber-events is not fully covered by insurance, it could adversely affect PSE's financial condition and results of operations.

Natural disasters like wildfires and catastrophic events, including terrorist acts, may adversely affect PSE's business. Events such as fires, earthquakes, explosions, floods, tornadoes, extreme weather events, vandalism, terrorist acts, and other similar occurrences, could damage PSE's operational assets, including utility facilities, information technology infrastructure, distributed generation assets and pipeline assets. Such events could likewise damage the operational assets of PSE's suppliers or customers. These events could disrupt PSE's ability to meet customer requirements, significantly increase PSE's response costs, and significantly decrease PSE's revenues. Unanticipated events or a combination of events, failure in resources needed to respond to events, or a slow or inadequate response to events may have an adverse impact on PSE's operations, financial condition, and results of operations. The availability of insurance covering catastrophic events like wildfires, sabotage and terrorism may be limited or may result in higher deductibles, higher premiums, and more restrictive policy terms.

PSE is subject to the commodity price, delivery and credit risks associated with the energy markets. In connection with matching PSE's energy needs and available resources, PSE engages in wholesale sales and purchases of electric capacity and energy and, accordingly, is subject to commodity price risk, delivery risk, credit risk and other risks associated with these activities. Credit risk includes the risk that counterparties owing PSE money or energy will breach their obligations for delivery of energy supply or contractually required payments related to PSE's energy supply portfolio. Should the counterparties to these arrangements fail to perform, PSE may be forced to enter into alternative arrangements. In that event, PSE's financial results could be adversely affected. Although PSE takes into account the expected probability of default by counterparties, the actual exposure to a default by a particular counterparty could be greater than predicted.

Costs of compliance with environmental, climate change and endangered species laws are significant and the costs or reduced revenue related to compliance with new and emerging laws and regulations and the occurrence of associated liabilities could adversely affect PSE's results of operations. PSE's operations are subject to extensive federal, state and local laws and regulations relating to environmental issues, including air emissions and climate change, endangered species protection, remediation of contamination, avian protection, waste handling and disposal, decommissioning, water protection and siting new facilities. In addition, recent laws proposed or passed by the State of Washington and various municipalities in PSE's service territory, including Seattle, seek to reduce or eliminate the use of natural gas in various contexts, such as for space and water heating in new commercial and multifamily buildings. As a result of these legal requirements, PSE must spend significant sums of money to comply with these measures including resource planning, remediation, monitoring, analysis, adoption of mitigation measures, use of pollution control equipment, and emissions-related abatement and fees. New environmental laws and regulations affecting PSE's operations or restricting the use of products sold by PSE may be adopted, and new interpretations of existing laws and regulations could be adopted or become applicable to PSE or its facilities. Compliance with these or other future regulations could require significant expenditures by PSE or reduce revenue and thus adversely affect PSE financially. In addition, PSE may not be able to recover all of its costs for such expenditures through electric and natural gas rates in a timely manner.

Under current law, PSE is also generally responsible for any on-site liabilities associated with the environmental condition of the facilities that it currently owns or operates or has previously owned or operated. The occurrence of a material environmental liability or new regulations governing such liability could result in substantial future costs and have a material adverse effect on PSE's results of operations and financial condition. Specific to climate change, Washington State has

adopted both renewable portfolio standards and GHG legislation, including CETA and CCA, and PSE anticipates full compliance with these requirements.

In 2021, the Washington Legislature adopted the CCA, which establishes a GHG emissions cap-and-invest program that caps GHG emissions beginning on January 1, 2023 and makes further reductions to the cap annually through 2050. The WDOE published final regulations to implement the program on September 29, 2022, which became effective on October 30, 2022. WDOE also indicated that they will have subsequent rulemakings that will build off initial rulemaking as program implementation gets underway and progress with Washington State carbon goals are evaluated. In general, the program will require covered entities to obtain emission allowances or offset credits for covered emissions and the WDOE provides the annual allowance budget based on the cap. Allowances can be obtained through quarterly auctions, or bought and sold on a secondary market. The CCA regulates PSE both as an electric utility and as a natural gas distribution utility. PSE is required to obtain emission allowances or offset credits for GHG emissions associated with electricity generated in or imported into the state to serve Washington State load, and all electricity generated by Washington State PSE facilities with total annual emissions exceeding 25,000 metric tons of carbon dioxide equivalent per year. As an electric utility subject to Washington's CETA, PSE will receive emission allowances at no cost through 2050 for direct emissions associated with electricity used to serve Washington State load to mitigate impacts to ratepayers. PSE will also be required to obtain emission allowances for GHG emissions associated with natural gas supplied to customers and any natural gas system associated facilities with emissions that exceed 25,000 metric tons of carbon dioxide equivalent per year. Based on the rules passed in 2022, there is potential for PSE's compliance with the CCA to result in increased costs to customers or amounts that PSE may not be able to recover through electric and natural gas rates. Potential risks associated with CCA compliance could include: the evolving nature of the CCA rulemaking as indicated by WDOE, market uncertainty based on rule interpretation during implementation, unresolved recovery methodology for CCA's impact on energy costs, company costs, customer rate impacts, and cash, liquidity and credit volatility.

PSE's inability to adequately develop or acquire the necessary infrastructure to comply with new and emerging laws and regulations could have a material adverse impact on our business and results of operations. Potential changes in regulatory standards, impacts of new and existing laws and regulations, including environmental laws and regulations and those seeking to combat climate change, and the need to obtain various regulatory approvals create uncertainty surrounding our energy resource portfolio. The current abundance of low, stably priced natural gas, together with environmental, regulatory, and other concerns surrounding coal-fired generation resources, fossil fuel infrastructure bans, and energy resource portfolio requirements, including those related to renewables development and energy efficiency measures, create strategic challenges as to the appropriate generation portfolio and fuel diversification mix.

In expressing concerns about the environmental and climate-related impacts from continued extraction, transportation, delivery and combustion of fossil fuels including natural gas, environmental advocacy groups and other third parties have in recent years undertaken greater efforts to oppose the permitting and construction of natural gas infrastructure projects. These efforts may increase in scope and frequency depending on a number of variables, including the future course of local, state and federal environmental regulation and the increasing financial resources devoted to these opposition activities. PSE cannot predict the effect that any such opposition may have on our ability to develop and construct natural gas infrastructure projects in the future.

PSE's operating results fluctuate on a seasonal and quarterly basis and can be impacted by various impacts of climate change. PSE's business is seasonal and weather patterns can have a material impact on its revenue, expenses and operating results. Demand for electricity is greater in the winter months associated with heating. Accordingly, PSE's operations have historically generated less revenue and income when weather conditions are milder in winter. In the event that the Company experiences unusually mild winters, its results of operations and financial condition could be adversely affected. PSE's hydroelectric resources are also dependent on snow conditions in the Pacific Northwest.

PSE may be adversely affected by extreme events in which PSE is not able to promptly respond, repair and restart the electric and natural gas infrastructure system. PSE must maintain an emergency planning and training program to allow PSE to quickly respond to extreme events. Without emergency planning, PSE is subject to availability of outside contractors during an extreme event which may impact the quality of service provided to PSE's customers and also require significant expenditures by PSE. In addition, a slow or ineffective response to extreme events may have an adverse effect on earnings as customers may be without electricity and natural gas for an extended period of time.

PSE depends on its work force and third party vendors to perform certain important services and may be negatively affected by its inability to attract and retain professional and technical employees or the unavailability of vendors. PSE is subject to workforce factors, including but not limited to loss or retirement of key personnel and availability of qualified personnel. PSE's ability to implement a workforce succession plan is dependent upon PSE's ability to employ and retain skilled professional and technical workers. Without a skilled workforce, PSE's ability to provide quality service to PSE's customers and to meet regulatory requirements could affect PSE’s earnings. Also, the costs associated with attracting and retaining qualified employees could reduce earnings and cash flows.

PSE continues to be concerned about the availability of skilled workers for special complex utility functions. PSE also hires third party vendors to perform a variety of normal business functions, such as power plant maintenance, data warehousing and management, electric transmission, electric and natural gas distribution construction and maintenance, certain billing and metering processes, call center overflow and credit and collections. The unavailability of skilled workers or unavailability of such vendors could adversely affect the quality and cost of PSE’s natural gas and electric service and accordingly PSE’s results of operations.

Potential municipalization may adversely affect PSE's financial condition. PSE may be adversely affected if we experience a loss in the number of our customers due to municipalization or other related government action. When a town, city, county, or portion of a county in PSE's service territory establishes its own municipal-owned utility or public utility district, it acquires PSE's assets and takes over the delivery of energy services that PSE provides. Although PSE is compensated in connection with the government entity's acquisition of its assets, any such loss of customers and related revenue could negatively affect PSE's future financial condition.

Technological developments may have an adverse impact on PSE's financial condition. Advances in power generation, energy efficiency and other alternative energy technologies, such as solar generation, could lead to more wide-spread use of these technologies, thereby reducing customer demand for the energy supplied by PSE which could negatively impact PSE's revenue and financial condition.

PSE may face risks related to the COVID-19 pandemic and other outbreaks that could have a material adverse impact on our business and results of operations. Business disruptions arising from pandemics, such as COVID-19, may adversely affect economic activity within Washington State and the United States of America. Efforts to contain and mitigate such pandemics and/or outbreaks (including, but not limited to, voluntary and mandatory quarantines, vaccination requirements, restrictions on travel, limiting gatherings of people, and reduced operations and extended closures of many businesses and institutions) could materially impact our results of operations, financial condition and ongoing operations. The impacts include but are not limited to:

- impacting customer demand for electricity and natural gas by our customers, particularly from commercial and industrial customers;
- reducing the availability and productivity of our employees;
- reducing the availability and productivity of key contractors and vendors;
- causing us to experience an increase in costs as a result of our emergency measures, delayed payments from our customers and uncollectible accounts;
- causing delays and disruptions in the availability of and timely delivery of materials and components used in our operations;
- causing a deterioration in our financial metrics or the business environment that impacts our credit ratings;
- causing significant disruption in the financial markets which could have a negative impact on our ability to access capital in the future and cost of capital;
- resulting in our inability to meet the requirements of the covenants in our existing credit facilities, including covenants regarding the ratio of total debt to total capitalization; and
- disrupting our ability to meet customer requirements and potentially significantly increase response costs.

PSE could be adversely affected by disruptions in the global economy and rising geopolitical tensions caused by the ongoing military conflict between Russia and Ukraine. The global economy has been negatively impacted by the military conflict between Russia and Ukraine. Governments including the U.S., United Kingdom, and European Union imposed import and export controls on certain products and economic sanctions on certain industries and parties in Russia. Further escalation of geopolitical tensions related to the military conflict, including increased trade barriers or restrictions on global trade, could result in, among other things, cyberattacks, supply chain disruptions, and increased costs, including energy costs, which may adversely affect our business and supply chain.

RISKS RELATING TO PUGET ENERGY'S AND PSE'S FINANCING

The Company's business is dependent on its ability to successfully access capital. The Company relies on access to internally generated funds, bank borrowings through multi-year committed credit facilities and short-term money markets as sources of liquidity and longer-term debt markets to fund PSE's utility construction program and other capital expenditure requirements of PSE. If Puget Energy or PSE are unable to access capital on reasonable terms, their ability to pursue improvements or acquisitions, including generating capacity, which may be necessary for future growth, could be adversely affected. Capital and credit market disruptions, a downgrade of Puget Energy's or PSE's credit rating or the unavailability of or the imposition of restrictions on borrowings under their credit facilities in the event of a deterioration of financial condition of Puget Energy or PSE may increase Puget Energy's and PSE’s cost of borrowing or adversely affect the ability to access one or more financial markets.

The amount of the Company's debt could adversely affect its liquidity and results of operations. Puget Energy and PSE have short-term and long-term debt, and may incur additional debt (including secured debt) in the future. Puget Energy has access to a multi-year $800.0 million revolving credit facility, secured by substantially all of its assets, which has a maturity date of May 14, 2027. There was $118.6 million outstanding under the facility as of December 31, 2022. Puget Energy's credit facility includes an expansion feature that could, subject to the commitment of one or more lenders, increase the size of the facility to $1.3 billion. PSE also has a separate credit facility, which provides PSE with access to a multi-year $800.0 million revolving credit facility, and includes an expansion feature that could, subject to the commitment of one or more lenders, increase the size of the facility to $1.4 billion. The PSE credit facility matures on May 14, 2027. As of December 31, 2022, no amounts were drawn and outstanding under the PSE credit facility. In addition, Puget Energy has issued $2.0 billion in senior secured notes, whereas PSE, as of December 31, 2022, had approximately $4.8 billion outstanding under first mortgage bonds, pollution control bonds and senior notes. The Company's debt level could have important effects on the business, including but not limited to:

- Making it difficult to satisfy obligations under the debt agreements and increasing the risk of default on the debt obligations;
- Making it difficult to fund non-debt service related operations of the business; and
- Limiting the Company's financial flexibility, including its ability to borrow additional funds on favorable terms or at all.

A downgrade in Puget Energy’s or PSE’s credit rating could negatively affect the ability to access capital, the ability to hedge in wholesale markets and the ability to pay dividends. Although neither Puget Energy nor PSE has any rating downgrade provisions in its credit facilities that would accelerate the maturity dates of outstanding debt, a downgrade in the Companies’ credit ratings could adversely affect the ability to renew existing or obtain access to new credit facilities and could increase the cost of such facilities. For example, under Puget Energy’s and PSE’s facilities, the borrowing spreads over the Secured Overnight Financing Rate (SOFR) (or other applicable index) and commitment fees increase if their respective corporate credit ratings decline. A downgrade in commercial paper ratings could increase the cost of commercial paper and limit or preclude PSE’s ability to issue commercial paper under its current programs.

Any downgrade below investment grade of PSE’s corporate credit rating could cause counterparties in the wholesale electric, wholesale natural gas and financial derivative markets to request PSE to post a letter of credit or other collateral, make cash prepayments, obtain a guarantee agreement or provide other mutually agreeable security, all of which would expose PSE to additional costs.

PSE may not declare or make any dividend distribution unless on the date of distribution PSE’s corporate credit/issuer rating is investment grade, or if its credit ratings are below investment grade, PSE’s ratio of earnings before interest, tax, depreciation and amortization (EBITDA) to interest expense for the most recently ended four fiscal quarter periods prior to such date is equal to or greater than 3.0 to 1.0.

Changes in the method for determining LIBOR and the potential replacement of LIBOR may affect our credit facilities and the interest rates on such borrowings. LIBOR, the London interbank offered rate, is the basic rate of interest used in lending between banks on the London interbank market and is widely used as a reference for setting the interest rate on loans globally. In July 2017, the United Kingdom’s Financial Conduct Authority, which regulates LIBOR announced that it intends to phase out LIBOR by the end of 2021. In November 2020, LIBOR’s administrator indicated that US dollar LIBOR will likely continue to be published until June 30, 2023, which would allow time for certain legacy contracts to mature before US dollar LIBOR is no longer available. If the method for calculation of LIBOR changes, if LIBOR is no longer available or if

lenders have increased costs due to changes in LIBOR, Puget Energy or PSE may suffer from potential increases in interest rates on any borrowings. In May 2022, Puget Energy and PSE entered into new revolving credit facilities that eliminated LIBOR as the benchmark for floating rate loans and replaced it with the Secured Overnight Financing Rate (SOFR) as the new benchmark rate for floating rate loans plus a spread that is based upon Puget Energy’s or PSE’s credit ratings, respectively.

Poor performance of pension and postretirement benefit plan investments and other factors impacting plan costs could unfavorably impact PSE’s cash flow and liquidity. PSE provides a defined benefit pension plan and postretirement benefits to certain PSE employees and former employees. Costs of providing these benefits are based, in part, on the value of the plan’s assets and the current interest rate environment and therefore, adverse market performance or low interest rates could result in lower rates of return for the investments that fund PSE’s pension and postretirement benefits plans and could increase PSE’s funding requirements related to the pension plans. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions, may also increase PSE's funding requirements related to the pension plans. Any contributions to PSE’s plans in 2023 and beyond as well as the timing of the recovery of such contributions in GRCs could impact PSE’s cash flow and liquidity.

RISKS RELATING TO PUGET ENERGY'S CORPORATE STRUCTURE

Puget Energy's ability to pay dividends may be limited. As a holding company with no significant operations of its own, the primary source of funds for the repayment of debt and other expenses, as well as payment of dividends to its shareholder, is cash dividends PSE pays to Puget Energy. PSE is a separate and distinct legal entity and has no obligation to pay any amounts to Puget Energy, whether by dividends, loans or other payments. The ability of PSE to pay dividends or make distributions to Puget Energy, and accordingly, Puget Energy’s ability to pay dividends or repay debt or other expenses, will depend on PSE’s earnings, capital requirements and general financial condition. If Puget Energy does not receive adequate distributions from PSE, it may not be able to meet its obligations or pay dividends.

The payment of dividends by PSE to Puget Energy is restricted by provisions of certain covenants applicable to long-term debt contained in PSE’s electric and natural gas mortgage indentures. In addition, beginning February 2009, pursuant to the terms of the Washington Commission merger order, PSE may not declare or pay dividends if PSE's common equity ratio calculated on a regulatory basis is 44.0% or below, except to the extent a lower equity ratio is ordered by the Washington Commission. Also, pursuant to the merger order, PSE's ability to declare or make any distribution is limited by its' corporate credit/issuer rating and EBITDA to interest ratio, as previously discussed above. The common equity ratio, calculated on a regulatory basis, was 48.1% at December 31, 2022, and the EBITDA to interest expense was 5.0 to 1.0 for the twelve-months ended December 31, 2022.

PSE's ability to pay dividends is also limited by the terms of its credit facilities, pursuant to which PSE is not permitted to pay dividends during any Event of Default (as defined in the facilities), or if the payment of dividends would result in an Event of Default, such as failure to comply with certain financial covenants.

Challenges relating to the operation of the Tacoma LNG facility could adversely affect the Company's operations. The Tacoma LNG facility at the Port of Tacoma, a facility jointly owned by PSE and Puget Energy's subsidiary, Puget LNG, is intended to provide peak-shaving services to PSE's natural gas customers, and to provide LNG as fuel primarily to the maritime market. Puget LNG has entered into one fuel supply agreement with a maritime customer, and is marketing the facility's expected output to other potential customers. Delays in the facility's operation or in its ability to timely deliver fuel to customers could expose Puget LNG to damages under one or more fuel supply contracts, which could unfavorably impact Puget Energy's return on investment.

GENERAL RISK FACTORS

The Company may be negatively affected by unfavorable changes in the tax laws or their interpretation. The Company's tax obligations include income, real estate, public utility, municipal, sales and use, business and occupation and employment-related taxes and ongoing audits related to these taxes. Changes in tax law, related regulations or differing interpretation or enforcement of applicable law by the IRS or other taxing jurisdiction could have a material adverse impact on the Company's financial statements. The tax law, related regulations and case law are inherently complex. The Company must make judgments and interpretations about the application of the law when determining the provision for taxes. These judgments may include reserves for potential adverse outcomes regarding tax positions that may be subject to challenge by the

taxing authorities. Disputes over interpretations of tax laws may be settled with the taxing authority in examination, upon appeal or through litigation.

Potential legal proceedings and claims could increase the Company's costs, reduce the Company's revenue and cash flow, or otherwise alter the way the Company conducts business. The Company is, from time to time, subject to various legal proceedings and claims. Any such claims, whether with or without merit, could be time-consuming and expensive to defend and could divert management's attention and resources. While management believes the Company has reasonable and prudent insurance coverage and accrues loss contingencies for all known matters that are probable and can be reasonably estimated, the Company cannot assure that the outcome of all current or future litigation will not have a material adverse effect on the Company and/or its results of operations.

The Company's costs and expenses could increase as a result of inflationary pressures. Such inflationary pressures could result in increased labor, commodities, materials and supplies, outside services and capital costs, among others, that may not be offset by an increase in revenues, which would adversely affect the Company's results of operations. While regulatory mechanisms exist to mitigate the impacts of inflation on commodity prices, the Company cannot assure that rising inflation will not have an adverse effect on the Company's results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The principal electric generating plants and underground natural gas storage facilities owned by PSE are described under Item 1, Business – Electric Supply and Natural Gas Supply. PSE owns its transmission and distribution facilities and various other properties. Substantially all properties of PSE are subject to the liens of PSE's mortgage indentures. The Company's corporate headquarters is housed in a leased building located in Bellevue, Washington.

ITEM 3. LEGAL PROCEEDINGS

Effective in November 2020, the SEC Final Rule Release No. 33-10825, "Modernization of Regulation S-K Items 101, 103, and 105" updated the disclosure threshold for environmental proceedings. Prior to this rule, environmental proceedings to which the government is a party were required to be disclosed if the proceeding was expected to result in sanctions of $100,000 or more. The rule increases the quantitative threshold to $300,000, but also permits registrants to elect a higher threshold, limited to the lesser of $1 million or 1% of consolidated current assets, if the registrant determines that such threshold is more reasonably designed to result in the disclosure of material environmental proceedings. Given the size of the Company's operations, PSE elected a threshold of $1 million. For information on litigation or legislative rulemaking proceedings, see Note 15, "Litigation" to the consolidated financial statements included in Item 8 of this report.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED SHAREHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

All of the outstanding shares of Puget Energy's common stock, the only class of common equity of Puget Energy, are held by its direct parent Puget Equico LLC (Puget Equico), which is an indirect wholly-owned subsidiary of Puget Holdings, and are not publicly traded. The outstanding shares of PSE's common stock, the only class of common equity of PSE, are held by Puget Energy and are not publicly traded.

The payment of dividends on PSE common stock to Puget Energy is restricted by provisions of certain covenants applicable to long-term debt contained in PSE's mortgage indentures in addition to terms of the Washington Commission merger order. Puget Energy's ability to pay dividends is also limited by the merger order issued by the Washington Commission as well as by the terms of its credit facilities. For further discussion, see Item 1A, "Risk Factors"- Risks Relating to Puget Energy's Corporate Structure and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in this report.

From time to time, when deemed advisable and permitted, PSE and Puget Energy pay dividends on its common stock. During 2022, 2021, and 2020, PSE paid dividends to its parent, Puget Energy, and Puget Energy paid dividends to its parent, Puget Equico, in the amounts shown in Puget Energy's and PSE's Consolidated Statements of Common Shareholder's Equity, included in Item 8, "Financial Statements and Supplementary Data" of this report.

ITEM 6. [Reserved]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis is intended to promote understanding of the results of operations and financial condition, is provided as a supplement to, and should be read in conjunction with the financial statements and related notes thereto included elsewhere in this report on Form 10-K. This section generally discusses the results of operations and changes in financial condition for 2022 compared to 2021. For discussion related to the results of operations and changes in financial condition for 2021 compared to 2020 refer to Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations in our fiscal year 2021 Form 10-K, which was filed with the United States Securities and Exchange commission (SEC). The discussion contains forward-looking statements that involve risks and uncertainties, such as Puget Energy, Inc. (Puget Energy) and Puget Sound Energy, Inc. (PSE) objectives, expectations and intentions. Words or phrases such as "anticipates," "believes," "continues," "could," "estimates," "expects," "future," "intends," "may," "might," "plans," "potential," "predicts," "projects," "should," "will likely result," "will continue" and similar expressions are intended to identify certain of these forward-looking statements. However, these words are not the exclusive means of identifying such statements. In addition, any statements that refer to expectations, projections or other characterizations of future events or circumstances are forward-looking statements. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this report. Puget Energy's and PSE's actual results could differ materially from results that may be anticipated by such forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed in the section entitled "Forward-Looking Statements" and "Risk Factors" included elsewhere in this report. Except as required by law, neither Puget Energy nor PSE undertakes any obligation to revise any forward-looking statements in order to reflect events or circumstances that may subsequently arise. Readers are urged to carefully review and consider the various disclosures made in this report and in Puget Energy's and PSE's other reports filed with the SEC that attempt to advise interested parties of the risks and factors that may affect Puget Energy's and PSE's business, prospects and results of operations.

Overview

Puget Energy is an energy services holding company and substantially all of its operations are conducted through its wholly-owned subsidiary PSE, a regulated electric and natural gas utility company. PSE is the largest electric and natural gas utility in the state of Washington, primarily engaged in the business of electric transmission, distribution and generation and natural gas distribution. Puget Energy's business strategy is to generate stable cash flows by offering reliable electric and natural gas service in a cost-effective manner through PSE. Puget Energy also has a wholly-owned non-regulated subsidiary, Puget LNG, LLC (Puget LNG), which has the sole purpose of owning, developing and financing the non-regulated activity of the Tacoma liquefied natural gas (LNG) facility. All of Puget Energy's common stock is indirectly owned by Puget Holdings LLC (Puget Holdings). Puget Holdings is owned by a consortium of long-term infrastructure investors including the British Columbia Investment Management Corporation (BCIMC), the Alberta Investment Management Corporation (AIMCo), Ontario Municipal Employee Retirement System (OMERS), PGGM Vermogensbeheer B.V., Macquarie

Washington Clean Energy Investment, L.P., and Ontario Teachers' Pension Plan Board. Puget Energy and PSE are collectively referred to herein as "the Company."

PSE generates revenue and cash flow primarily from the sale of electric and natural gas services to residential and commercial customers within a service territory covering approximately 6,000 square miles, principally in the Puget Sound

region of the state of Washington. PSE continually balances its load requirements, generation resources, purchase power agreements, and market purchases to meet customer demand. The Company's external financing requirements principally reflect the cash needs of its construction program, its schedule of maturing debt and certain operational needs. PSE requires access to bank and capital markets to meet its financing needs.

Factors affecting PSE's performance are set forth in this "Overview" section, as well as in other sections of the Management's Discussion and Analysis.

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with U.S. Generally Accepted Accounting Principles (GAAP), as well as return on equity (ROE) excluding unrealized gains and losses on derivative instruments (net income plus unrealized losses and/or minus unrealized gains on derivative instruments divided by average common equity) that is considered a "non-GAAP financial measure". Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that includes adjustments that result in a presentation that is not defined by GAAP. The Company believes that its return on average of monthly averages (AMA) equity, also a non-GAAP measure, is a suitable metric for comparing ROE across years and is a relevant metric for assessing and evaluating ROE performance against the Company's authorized regulated ROE. The AMA equity is not intended to represent the regulated equity. PSE's ROE may not be comparable to other companies' ROE measures. Furthermore, this measure is not intended to replace ROE (GAAP net income divided by GAAP average common equity) as an indicator of operating performance.

The following table presents PSE's ROE, its return on AMA equity and its authorized regulated ROE for 2022 and 2021:

	2022			2021		
(Dollars in Thousands)	Earnings	Average Common Equity	Return on Equity	Earnings	Average Common Equity	Return on Equity
Return on equity	$490,952	$4,613,257	10.6%	$336,063	$4,268,420	7.9%
Less/Plus: Unrealized gains and losses on derivative instruments, after-tax	(206,330)	—	*	(10,890)	—	*
Plus: Equity adjustments[1]	—	(108,984)	*	—	104,731	*
Plus: Impact of average of monthly average (AMA)	—	127,482	*	—	97,767	*
Return on AMA equity	$284,622	$4,631,755	6.1%	$325,173	$4,470,918	7.3%
Authorized regulated return on equity[2]			9.4%			9.4%

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1. *Equity adjustments are related to removing the impacts of accumulated other comprehensive income (AOCI), subsidiary retained earnings, retained earnings of derivative instruments, and decoupling 24-month revenue reserve.*
2. *The authorized regulated return on equity rate per the approved 2019 GRC is 9.4% for natural gas and electric effective October 1, 2020 and October 15, 2020, respectively.*
* *Not meaningful and/or applicable.*

The Company's 2022 return on AMA equity was 6.1%, which is lower than the authorized regulated ROE primarily due to the following:

- Regulated equity (rate base multiplied by equity percent) was $589.3 million lower than AMA equity for the year ended December 31, 2022. The impact on ROE for this variance was negative 1.2%. The variance was primarily driven by investment in items that do not earn a return or earn a return that is less than the authorized ROE. Such items include investment in construction work in progress and growth in rate base since the last general rate case (GRC).
- Depreciation expense was $18.0 million higher than the amount allowed in rates on an after-tax basis for the year ended December 31, 2022, for an impact on ROE of negative 0.4%.
- Operations and maintenance expense, including production operations and maintenance, was $61.5 million higher than the amount allowed in rates on an after-tax basis for the year ended December 31, 2022, for an impact on ROE of negative 1.3%.

The Company's 2021 return on AMA equity was 7.3%, which is lower than the authorized regulated ROE primarily due to the following:

- Regulated equity (rate base multiplied by equity percent) was $630.3 million lower than AMA equity for the year ended December 31, 2021. The impact on ROE for this variance was negative 1.3%. The variance was primarily driven by investment in items that do not earn a return or earn a return that is less than the authorized ROE. Such items include investment in construction work in progress and growth in rate base since the last GRC.

- Depreciation expense was $26.8 million higher than the amount allowed in rates on a pre-tax basis for the year ended December 31, 2021, for an impact on ROE of negative 0.6%.

Factors and Trends Affecting PSE's Performance

PSE's ongoing regulatory requirements and operational needs necessitated the investment of substantial capital in 2022 and will continue to do so in future years. Because PSE intends to seek recovery of such investments through the regulatory process, its financial results depend heavily upon favorable outcomes from that process. The principal business, economic and other factors that affect PSE's operations and financial performance include:

- The rates PSE is allowed to charge for its services;
- PSE's ability to recover power costs that are included in rates which are based on volume;
- Weather conditions, including the impact of temperature on customer load; the impact of extreme weather events on budgeted maintenance costs; meteorological conditions such as snow-pack, stream-flow and wind-speed which affect power generation, supply and price;
- The effects of climate change, including changes in the environment that may affect energy costs or consumption, increase the Company's costs, or adversely affect its operations;
- Regulatory decisions allowing PSE to recover purchased power and fuel costs, on a timely basis;
- PSE's ability to supply electricity and natural gas, either through company-owned generation, purchase power contracts or by procuring natural gas or electricity in wholesale markets;
- Equal sharing between PSE and its customers of earnings which exceed PSE's authorized rate of return (ROR);
- Availability and access to capital and the cost of capital;
- Regulatory compliance costs, including those related to new and developing federal regulations of electric system reliability, state regulations of natural gas pipelines and federal, state and local environmental laws and regulations;
- Wholesale commodity prices of electricity and natural gas;
- Increasing capital expenditures with additional depreciation and amortization;
- Failure to complete capital projects on schedule and within budget or the abandonment of capital projects, either of which could result in the Company's inability to recover project costs;
- Tax reform, the effect of lower tax rates, and regulatory treatment of excess deferred tax balances on rate base and customer rates;
- General economic conditions, such as inflation, in PSE's service territory and its effects on customer growth and use-per-customer;
- Federal, state, and local taxes;
- Employee workforce factors, including potential strikes, work stoppages, transitions in senior management, and loss or retirement of key personnel and availability of qualified personnel;
- The effectiveness of PSE's risk management policies and procedures;
- Cyber security attacks, data security breaches, or other malicious acts that cause damage to the Company's generation and transmission facilities or information technology systems, or result in the release of confidential customer, employee, or Company information;
- Acts of war or terrorism locally or abroad, or the impact of civil unrest to infrastructure or preventing access to infrastructure and its impact on the supply chain and prices of goods and services; and
- Risks due to pandemics, including supply shortages, rising costs, disruption to vendor or customer relationships, the potential for reputational harm, the impact of government, business and company closure of facilities, customer or contract defaults, concerns of safety to employees and customers, potential costs due to quarantining of employees and work-from-home policies, and the Company's and vendor staffing levels resulting from vaccination mandates.

Regulation of PSE Rates and Recovery of PSE Costs

PSE's regulatory requirements and operational needs require the investment of substantial capital in 2022 and future years. As PSE intends to seek recovery of these investments through the regulatory process, its financial results depend heavily upon outcomes from that process. The rates that PSE is allowed to charge for its services influence its financial condition, results of operations and liquidity. PSE is highly regulated and the rates that it charges its retail customers are approved by the Washington Commission. The Washington Commission has traditionally required these rates be determined based, to a large extent, on historic test year costs plus weather normalized assumptions about hydroelectric conditions and power costs in the relevant rate year. Incremental customer growth and sales typically have not provided sufficient revenue to cover general cost increases over time due to the combined effects of regulatory lag and attrition. Absent a resolution for the impact of lag and attrition, the Company will need to seek rate relief through a rate case with the Washington Commission. The Washington Commission determines whether the Company's expenses and capital investments are reasonable and prudent for the provision of cost-effective, reliable and safe electric and natural gas service. If the Washington Commission determines that a capital investment is not reasonable or prudent, the costs (including return on any resulting rate base) related to such capital investment may be disallowed, partially or entirely, and not recovered in rates.

Washington state law also requires PSE to pursue electric conservation that is cost-effective, reliable and feasible. PSE's mandate to pursue electric conservation initiatives may have a negative impact on the electric business financial performance due to lost margins from lower sales volumes as variable power costs are not part of the decoupling mechanism. The Washington Commission and Washington state law also set natural gas conservation achievement standards for PSE. The effects of achieving these standards will, however, have only a slight negative impact on natural gas business financial performance due to the natural gas business being almost fully decoupled.

On May 3, 2021, the Washington Governor signed legislation passed by the state legislature that would require investor-owned utilities to file a multiyear rate plan for two, three, or four years as part of a GRC filed with the Washington Commission on or after January 1, 2022. For the initial rate year, the legislation requires the Washington Commission to ascertain and determine the fair value for rate-making purposes of the property in service as of the date that rates go into effect. Utilities would be bound to the first and second year of a multiyear rate plan and can file for a new rate plan in years three or four. If a company earns greater than a half percent above its authorized rate of return on a regulated basis, revenues above the level must be deferred for funds to customers or another determination by the Washington Commission in a subsequent adjudicative proceeding. The Washington Commission must also set performance measurements to assess a natural gas or electric company operating under a multiyear rate plan.

General Rate Case Filing

2022 GRC

PSE filed a GRC which includes a three-year multiyear rate plan with the Washington Commission on January 31, 2022, requesting an overall increase in electric and natural gas rates of 13.6% and 13.0% respectively in 2023; 2.5% and 2.3%, respectively in 2024; and 1.2% and 1.8%, respectively, in 2025. PSE requested a return on equity of 9.9% in all three rate years. PSE requested an overall rate of return of 7.39% in 2023; 7.44% in 2024; and 7.49% in 2025. The filing requested recovery of forecasted plant additions through 2022 as required by Revised Code of Washington (RCW) 80.28.425 as well as forecasted plant additions through 2025, the final year of the multiyear rate plan.

In August 2022, three separate partial multiparty settlement agreements were reached. On August 5, 2022, parties filed an unopposed partial multiparty settlement agreement relating to the Voluntary Long Term Renewable Energy Purchase rider, known as Green Direct, resolving the method for calculating the energy credit Green Direct customers receive, among other matters. On August 26, 2022, six of the sixteen parties, including PSE, filed a partial multiparty settlement agreement with the Washington Commission determining that the regulated portion of the Tacoma LNG Facility will be included in rates, as a tracker, beginning November 2023. Also, on August 26, 2022, twelve of the sixteen parties, including PSE, filed a partial multiparty settlement agreement with the Washington Commission for the remaining items in the GRC. The GRC settlement agreement set a two year rate plan instead of a three year plan as originally filed, provided a capital structure of 49.0% equity and 51.0% debt, and a return on equity of 9.4% with an overall rate of return of 7.16%.

On December 22, 2022, the Washington Commission issued an order on PSE's 2022 GRC which approved, with conditions, three settlement agreements which cover a two-year period beginning January 1, 2023. The ruling provided for a weighted cost of capital of 7.16%, or 6.62% after-tax, and a capital structure of 49.0% in common equity in 2023 and 49.5% in common equity in 2024, with a return on equity of 9.4%. The order also provided for an update to power costs in 2023 and 2024 and authorizes PSE to seek recovery of the costs related to the Tacoma LNG Facility concurrent with its 2023 PGA filing. PSE is also allowed to file two additional trackers that will request to recover all rate base, depreciation, and operations and maintenance (O&M) expenses related to investments under the Company's Clean Energy Implementation Plan (CEIP) and Transportation Electrification Plan.

On December 27, 2022 PSE submitted compliance filings, including an update to power costs, and revised tariff sheets to comply with the order. On January 6, 2023, the Washington Commission rejected the compliance filing, in part; and required a revised compliance filing specific to electric rates to remove an additional $135.8 million related to PSE's recovery of projected costs related to the modeling of the Climate Commitment Act's impacts on PSE's use of natural gas and coal-fired resources that had been included as part of PSE's update to power costs in the compliance filing. Per the order, PSE is allowed to either defer the $135.8 million in projected power costs and may submit a request for recovery of those costs either in its 90-day compliance filing for 2024 forecasted power costs or file a petition for Washington Commission review of these costs in a separate proceeding.

Natural gas rates became effective on January 7, 2023, resulting in a $70.8 million increase in natural gas base revenue in 2023 and a $19.5 million increase in 2024, representing increases of 6.4% and 1.65%, respectively. On January 10, 2023, the Washington Commission accepted the revised compliance filing with electric rates going into effect on January 11, 2023. The revisions reflected a final base electric revenue increase of $247.0 million in 2023 and $33.1 million in 2024, which represents an increase of 10.75% and 1.33%, respectively.

2019 GRC

PSE filed a GRC with the Washington Commission on June 20, 2019, requesting an overall increase in electric and natural gas rates of 6.9% and 7.9% respectively. On July 8, 2020, the Washington Commission issued its order on PSE's 2019 GRC. The ruling provided for a weighted cost of capital of 7.39% or 6.8% after-tax, and a capital structure of 48.5% in common equity with a return on equity of 9.4%. The order also resulted in a combined net increase to electric of $29.5 million, or 1.6%, and to natural gas of $36.5 million, or 4.0%. However, the Washington Commission extended the amortization of certain regulatory assets, PSE's electric decoupling deferral, and PSE's purchases gas adjustment (PGA) deferral to mitigate the impact of the rate increase in response to the economic uncertainty created by the COVID-19 pandemic. This reduced the electric revenue increase to approximately $0.9 million, or 0.1% and the natural gas increase to $1.3 million, or 0.2% and became effective October 15, 2020 and October 1, 2020, respectively.

On August 6, 2020, PSE filed a petition for judicial review with the Superior Court of the State of Washington for King County challenging the portion of the final order that requires PSE to pass back to customers the reversal of plant-related excess deferred income taxes in a manner that may deviate from the Internal Revenue Service (IRS) normalization and consistency rules.

PSE requested a Private Letter Ruling (PLR) from the IRS regarding this matter. On October 7, 2020, PSE, the Washington Commission and interveners agreed to dismiss the petition for judicial review. The agreement was based on a commitment from the Washington Commission that if the IRS ruling finds that the Washington Commission's methodology for reversing plant-related excess deferred income taxes is impermissible, the Washington Commission would open a proceeding to review and enact the changes required by the IRS ruling. There was approximately $25.6 million in annual revenue requirement related to the 2019 GRC, which PSE requested it be allowed to track and recover.

In July 2021, PSE received a Private Letter Ruling (PLR) from the IRS which concluded that in the 2019 GRC the Washington Commission's methodology for reversing plant-related excess deferred income taxes was an impermissible methodology under the IRS normalization and consistency rules. The PLR required adjustments to PSE's rates to bring PSE back into compliance with IRS rules. In September 2021, the Washington Commission amended its order in accordance with the PLR. The annualized overall rate impact was an increase of $15.8 million, or 0.7%, for electric and $3.1 million, or 0.3%, for natural gas for a total of $18.9 million with rates effective October 1, 2021. This led to an overall annualized net increase to electric rates of $77.1 million, or 3.7%, an increase of $17.5 million above the $59.6 million granted in the revised final order. The order also led to an overall annualized net increase to natural gas rates of $45.3 million, or 5.9%, an increase of $2.4 million above the $42.9 million granted in the revised final order. The Washington Commission maintained adjustments that mitigated the impacts of the rate increases in response to the economic instability created by the COVID-19 pandemic, which reduced the electric revenue increase to approximately $48.3 million, or 2.3%, and the natural gas increase to $4.9 million, or 0.6%.

For additional information, see Note 4, "Regulation and Rates" to the consolidated financial statements included in Item 8 of this report.

Power Cost Only Rate Case

On December 9, 2020, PSE filed its 2020 power cost only rate case (PCORC). The filing proposed an increase of $78.5 million (or an average of approximately 3.7%) in the Company's overall power supply costs with an anticipated effective date in June 2021. On February 2, 2021, PSE supplemented the PCORC to update its power costs, leading to a requested increase from $78.5 million to $88.0 million (or an average of approximately 4.1%).

On March 2, 2021, several of the parties to the PCORC reached a multiparty settlement in principle, which was unopposed. The settlement resulted in an estimated revenue increase of $65.3 million or 3.1%. On June 1, 2021, the Washington

Commission issued its Final Order approving and adopting the settlement and authorizing and requiring a power cost update through a compliance filing. On June 17, 2021, PSE filed a compliance filing with the Washington Commission with a revenue increase of $70.9 million or 3.3% due to the update on power costs with rates effective July 1, 2021.

The 2022 GRC Order in Docket No. UE-220066, set PCORC rates to zero effective January 11, 2023 and PSE agreed not to file a PCORC during 2023 and 2024, the two-year rate plan agreed to in the GRC settlement.

Revenue Decoupling Adjustment Mechanism

On December 23, 2020, the Washington Commission approved PSE's filing to update Schedule 142 decoupling amortization rates, with an effective date of January 1, 2021, by zeroing out rates still effective past October 15, 2020 on tariff sheet Schedule 142-H, which was replaced by rates on tariff sheet Schedule 142-I effective October 15, 2020. PSE included a true up of the over-collection amounts for the period of October 15, 2020 through December 31, 2020 in PSE's annual May 2021 decoupling filing.

On June 1, 2021, the Washington Commission approved a multi-party settlement agreement in PSE's PCORC that was originally filed on December 9, 2020. As part of this settlement agreement, the electric annual fixed power cost allowed revenue was updated to reflect changes in the approved revenue requirement. The changes took effect on July 1, 2021.

On September 28, 2021, the Washington Commission approved 2019 GRC filing updated to PLR changes. As part of this filing, the annual electric and gas delivery cost allowed revenue was updated to reflect changes in the approved revenue requirement. The changes took effect on October 1, 2021.

On January 6, 2023, the Washington Commission approved the natural gas 2022 GRC filing. As part of this filing the annual gas delivery allowed revenue was updated to reflect changes in the approved revenue requirement. Additionally, the Commission approved the removal of the earnings test from the decoupling mechanism in accordance with RCW 80.28.425(6). The changes took effect on January 7, 2023.

On January 10, 2023, the Washington Commission approved the electric 2022 GRC filing. As part of this filing the annual electric delivery and fixed power cost allowed revenue was updated to reflect changes in the approved revenue requirement. Additionally, the Commission approved the removal of the earnings test from the decoupling mechanism in accordance with RCW 80.28.425(6). The changes took effect on January 11, 2023.

On December 31, 2022, PSE performed an analysis to determine if electric and natural gas decoupling revenue deferrals would be collected from customers within 24 months of the annual period, per ASC 980. If not, for GAAP purposes only, PSE would need to record a reserve against the decoupling revenue and regulatory asset balance. Once the reserve is probable of collection within 24 months from the end of the annual period, the reserve can be recognized as decoupling revenue. The analysis indicated that electric and natural gas deferred revenue will be collected within 24 months of the annual period; therefore, no reserve adjustment was booked to 2022 electric or natural gas decoupling revenue.

The Washington Commission approved the following PSE requests to change rates for prior deferrals under its electric and natural gas decoupling mechanisms:

Average

Effective Date	Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)[1]
Electric:		
May 1, 2022[2]	(1.0)%	$(23.5)
May 1, 2021[3]	1.0	21.4
January 1, 2021	(1.0)	(20.6)
October 15, 2020[4]	(0.5)	(10.2)
May 1, 2020	0.2	2.0
Natural Gas:		
May 1, 2022	(0.7)%	$(7.4)
May 1, 2021	1.5	15.0
May 1, 2020	(0.5)	(4.8)

1. *For electric and natural gas rates effective May 1, 2022, May 1, 2021 and May 1, 2020, there were no excess earnings that impacted the approved revenue change.*
2. *For the electric rates effective May 1, 2022, there was $8.0 million of excess deferred revenues for delivery and fixed power costs which could not be set in rates until May 1, 2023 due to the 3% rate cap.*
3. *For the electric rates effective May 1, 2021, there was $24.1 million of excess deferred revenues for delivery and fixed power costs which could not be set in rates until May 1, 2022 due to the 3% rate cap.*
4. *The 2019 GRC final order lengthened the recovery period from the original one-year recovery to a two-year recovery of April 2022. The remaining decoupling amortization balances for delivery and fixed power costs of $1.7 million were included in electric decoupling mechanism tariff rates, effective May 1, 2022.*

Electric Rates

Colstrip Adjustment Rider

This schedule implements surcharges and/or credits to collect or pass back the costs incurred or benefits realized associated with Colstrip Power Plant Units 1 & 2 and 3 & 4 as authorized in Washington Commission Docket No. UE-220066. Beginning in 2026, only decommissioning and remediation related costs will be included in this Schedule in compliance with the Clean Energy Transformation Act.

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
January 11, 2023	2.2%	$50.3

Energy Charge Credit Recovery Adjustment

This schedule implements a surcharge to recover certain costs incurred under the electric Schedule 139 Voluntary Long Term Renewable Energy Purchase Rider as authorized in Washington Commission Docket No. UE-220066. The surcharge in this schedule will be updated with each filing that revises the Schedule 139 Energy Charge Credit.

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
January 11, 2023	1.5%	$35.3

Rates Not Subject to Refund Rate Adjustment

The purpose of this schedule is to recover costs approved during a multiyear rate plan period that are not subject to refund and that are above the level of base rates set in the multiyear rate plan as authorized in Washington Commission Docket No. UE-220066.

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)

January 11, 2023	7.9%	$182.5

Rates Subject to Refund Rate Adjustment

The purpose of this schedule is to charge customers the provisionally approved rates subject to refund approved in a multiyear rate plan, for property granted provisional approval for recovery as authorized in Washington Commission Docket No. UE-220066. PSE will file an annual review March 31st of each year, which will be reviewed by the Washington Commission.

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
January 11, 2023	4.0%	$91.7

Transportation Electrification Plan Adjustment Rider

This schedule implements surcharges to collect costs incurred associated with the implementation of the Company's Transportation Electrification Plan, and specifically the products and services offered under Schedules 551, 552, 553, 554, 555, 556, 557, 558, 559 and 583 as authorized in Washington Commission Docket No. UE-230040.

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
March 1, 2023	0.2%	$6.0

Conservation Service Rider

The following table sets forth conservation rider rate adjustments approved by the Washington Commission and the corresponding expected annual impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
May 1, 2022	1.0%	$21.6
May 1, 2021	(0.6)	(12.3)
May 1, 2020	0.9	17.8

Federal Incentive Tracker

The following table sets forth the federal incentive tracker tariff revenue requirement approved by the Washington Commission and the corresponding expected annual impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates from prior year	Total credit to be passed back to eligible customers (Dollars in Millions)
January 1, 2023[1]	1.3%	$1.0
January 1, 2022	0.1	(28.2)
January 1, 2021	0.3	(29.5)
January 1, 2020	(0.04)	(37.8)

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1. *The 2022 rate period represented the final year of the ten year period used to pass back the Treasury Grants included in Schedule 95A (Federal Incentive Tracker). The overall rate now represents a surcharge as amounts from the 2022 filing are expected to be over-distributed.*

Low Income Program

The following table sets forth the low income program funding adjustments approved by the Washington Commission and the corresponding expected annual impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
October 1, 2022	1.1%	$25.8
October 1, 2021	0.3	5.8

Power Cost Adjustment Clause

PSE updated its Schedule 95 rates in the Power Cost Adjustment Clause tariff to reflect the transition fee as required by Section 12 of the Special Contract, a non-prescribed commercial/industrial rate contract. Additionally, Schedule 95 rates also include portions of fixed power cost adjustments per the allowed decoupling rate re-allocation resulting from a Special Contract customer becoming a transportation customer as well as small variable power cost adjustments.

PSE exceeded the $20.0 million cumulative deferral balance in its PCA mechanism in 2020. The surcharging of deferrals can be triggered by the Company when the balance in the deferral account is a credit of $20.0 million or more. During 2020, actual power costs were higher than baseline power costs, thereby creating an under-recovery of $76.1 million. Under the terms of the PCA's sharing mechanism for under-recovered power costs, PSE absorbed $32.1 million of the under-recovered amount, and customers were responsible for the remaining $44.0 million, or $46.0 million including interest. PSE filed to recover the deferred balance in Docket No. UE-210300, and the Washington Commission allowed the recovery effective December 1, 2021.

Additionally, PSE exceeded the $20.0 million cumulative deferral balance in its PCA mechanism in 2021. During 2021, actual power costs were higher than baseline power costs; thereby, creating an under-recovery of $68.0 million. Under the terms of the PCA's sharing mechanism for under-recovered power costs, PSE absorbed $31.3 million of the under-recovered amount, and customers were responsible for the remaining $36.7 million, or $38.4 million including interest. On October 27, 2022, the Washington Commission approved PSE's 2021 PCA report that proposes to recover the deferred balance for 2021 PCA period by keeping the current rates and allowing recovery from January 1, 2023 through November 30, 2023.

The following table sets forth power cost adjustment clause filing approved by the Washington Commission and the corresponding expected annual impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
December 1, 2020[1]	2.1%	$43.9
October 15, 2020	(0.2)	(3.3)
July 3, 2020[2]	1.2	23.9

1. *The Schedule 95 PCA mechanism rates from the prior year that recover the 2019 imbalance (effective December 1, 2020) have been extending through December 31, 2022 to recover the imbalance attributable to 2020. As of October 27, 2022 in UE-220308 Final Order, the Washington Commission approved to extend PCA imbalance rates to recover the PCA imbalance attributable to 2021 from January 1, 2023 to November 30, 2023.*
2. *The rates for the Electric Special Contract were zeroed out effective July 3, 2020 following the July 2019 through June 2020 period. The actual residual amount resulting at July 31, 2020 were included in the electric Schedule 129 Low Income Program rates that became effective October 1, 2020.*

Power Cost Adjustment Mechanism

PSE currently has a power cost adjustment (PCA) mechanism that provides for the deferral of power costs that vary from the "power cost baseline" level of power costs. The "power cost baseline" levels are set, in part, based on normalized assumptions about weather and hydroelectric conditions. Excess power costs or savings are apportioned between PSE and its customers pursuant to the graduated scale set forth in the PCA mechanism and will trigger a surcharge or refund when the cumulative deferral trigger is reached.

Effective January 1, 2017, the following graduated scale is used in the PCA mechanism:

	Company's Share		Customers' Share	
Annual Power Cost Variability	Over	Under	Over	Under
Over or Under Collected by up to $17 million	100 %	100 %	— %	— %

Over or Under Collected by between $17 million - $40 million	35	50	65	50
Over or Under Collected beyond $40 + million	10	10	90	90

For the year ended December 31, 2022, in its PCA mechanism, PSE under recovered its allowable costs by $110.1 million of which $74.6 million was apportioned to customers and $1.5 million of interest was accrued on the deferred customer balance. This compares to an under recovery of allowable costs of $68.0 million for the year ended December 31, 2021, of which $36.7 million was apportioned to customers and accrued $1.7 million interest on the total deferred customer balance.

Property Tax Tracker

The following table sets forth property tax tracker mechanism rate adjustments approved by the Washington Commission and the corresponding expected annual impact on PSE’s revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
May 1, 2022	(0.3)%	$(5.8)
May 1, 2021	(0.1)	(1.7)
May 1, 2020	0.07	1.4

Residential and Farm Exchange Benefit

The following table sets forth residential and farm exchange benefit adjustments approved by the Washington Commission and the corresponding expected annual impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Total credit to be passed back to eligible customers (Dollars in Millions)
November 1, 2021	0.4%	$(75.7)

Natural Gas Rates

Distribution Pipeline Provisional Recovery Adjustment

This schedule implements surcharges in order to defer the revenues associated with the provisional recovery of $30.0 million for the four miles of distribution pipe to support proper allocation of the investments in a later filing as authorized in Washington Commission Docket No. UG-220067.

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
January 7, 2023	0.3%	$3.0

Rates Not Subject to Refund Rate Adjustment

The purpose of this schedule is to recover costs approved during a multiyear rate plan period that are not subject to refund and that are above the level of base rates set in the multiyear rate plan as authorized in Washington Commission Docket No. UG-220067.

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
January 7, 2023	(0.1)%	$(1.6)

Rates Subject to Refund Rate Adjustment

The purpose of this schedule is to charge customers the provisionally approved rates subject to refund approved in a multiyear rate plan, for property granted provisional approval for recovery as authorized in Washington Commission Docket No. UG-220067.

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
January 7, 2023	4.1%	$45.5

Conservation Service Rider

The following table sets forth conservation rider rate adjustments approved by the Washington Commission and the corresponding annual impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
May 1, 2022	0.3%	$3.2
May 1, 2021	(0.2)	(1.5)
May 1, 2020	0.4	3.5

Cost Recovery Mechanism for Pipeline Replacement

The following table sets forth cost recovery mechanism (CRM) rate adjustments approved by the Washington Commission and the corresponding impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
January 7, 2023[1]	(2.0)%	$(22.6)
November 1, 2022	0.4	4.6
November 1, 2021	0.5	4.9
November 1, 2020	1.2	10.6

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1. *Per 2022 GRC Final Order in Docket No. UG-220067, CRM rates on Schedule 149 were set to zero as of January 7, 2023.*

Low Income Program

The following table sets forth the low income program funding adjustments approved by the Washington Commission and the corresponding expected annual impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
October 1, 2022	(0.04)%	$(0.4)
October 1, 2021	(0.3)	(3.0)

Property Tax Tracker

The following table sets forth property tax tracker rate adjustments approved by the Washington Commission and the corresponding impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
May 1, 2022	0.02%	$0.2
May 1, 2021	0.3	3.2
May 1, 2020	(0.3)	(2.8)

Purchased Gas Adjustment

On October 28, 2021, the Washington Commission approved PSE's request for November 2021 PGA rates in Docket No. UG-210721, effective November 1, 2021. As part of that filing, PSE requested an annual revenue increase of $59.1 million; where PGA rates, under Schedule 101, increase annual revenue by $80.6 million, and the tracker rates under Schedule 106, decrease annual revenue by $21.5 million.

The annual 2021 PGA rate increases were in addition to continuing the collection on the remaining balance of $69.4 million under Supplemental Schedule 106B, which were set, in effect, through September 30, 2023 per the 2019 GRC.

On October 27, 2022, the Washington Commission approved PSE's request for PGA rates in Docket No. UG-220715, effective November 1, 2022. As part of that filing, PSE requested an annual revenue increase of $155.3 million; where PGA rates, under Schedule 101, increase annual revenue by $142.1 million, and the tracker rates under Schedule 106, increase annual revenue by $13.2 million.

On November 15, 2022, the FERC approved a settlement of a counterparty, FERC Docket No. RP17-346. Under the terms, PSE was allocated $24.2 million related to PSE natural gas services which was recorded on December 31, 2022 and included below. The 2022 GRC order requires PSE to amortize the refund in 2023 as a credit against natural gas costs and therefore pass back the refund to customers through the PGA mechanism.

The following table presents the PGA mechanism balances and activity at December 31, 2022 and December 31, 2021:

Puget Energy and
Puget Sound Energy

(Dollars in Thousands) PGA receivable balance and activity	December 31, 2022	December 31, 2021
PGA receivable beginning balance	$ 57,935	$ 87,655
Actual natural gas costs	457,950	364,775
Allowed PGA recovery	(496,879)	(396,236)
Interest	1,674	1,741
Refund from counterparty settlement	(24,216)	—
PGA (liability)/receivable ending balance	$ (3,536)	$ 57,935

The following table sets forth the PGA rate adjustment approved by the Washington Commission and the corresponding expected annual impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
November 1, 2022	14.9%	$155.3
November 1, 2021	5.8	59.1
November 1, 2020	7.7	70.0
October 1, 2020	(3.9)	(35.5)

Other Proceedings

Voluntary Long-Term Renewable Energy

PSE offers Green Direct to larger customers (aggregated annual loads greater than 10,000-megawatt hours (MWh)) and government customers. The initial resource option offered under this rate schedule is a wind generation facility with the capacity of approximately 136.8 MW, which went into operation on November 7, 2020. The project is fully subscribed and the twenty-one customers under phase 1 of the program began taking service in November 2020.

The Washington Commission approved a second phase of the Green Direct product in 2018. The phase 2 project is the 150 MW Lund Hill Solar facility located in Klickitat County, Washington. The solar facility declared full commercial operations on October 19, 2022 and will serve an additional twenty customers who enrolled in 2018. On March 1, 2021, the associated power purchase agreement went into effect under an interim supply agreement for renewable energy delivered to PSE's system; and thus, the phase 2 customers began receiving renewable energy under their agreement on March 1, 2021. All

Green Direct customers are now receiving a blend of the phase 1 wind and the renewable energy delivered under the phase 2 power purchase agreement.

Crisis Affected Customer Assistance Program

On April 6, 2020, PSE filed with the Washington Commission revisions to its currently effective electric and natural gas service tariffs. The purpose of this filing was to incorporate into PSE's low-income tariff a new temporary bill assistance program, Crisis Affected Customer Assistance Program (CACAP-1) (Dockets No. UE-200331 and UG-200332), to mitigate the economic impact of the COVID-19 pandemic on PSE's customers. CACAP allowed PSE customers facing financial hardship due to COVID-19 to receive up to $1,000 in bill assistance. The program made available $11.0 million in unspent low income funds from prior years, therefore resulting in no rate impact, and supplemented other forms of financial assistance. CACAP-1 ran from April 13, 2020, to September 30, 2020.

On March 28, 2021, the Washington Commission approved PSE's CACAP-2 (Dockets No. UE-210137 and UG-210138). With a program budget of $20.0 million for electric customers and $7.7 million for natural gas customers, CACAP-2, which ran from April 12, 2021, to March 29, 2022, provided up to $2,500 per year in bill assistance for arrearages for each qualifying low-income household.

On October 15, 2021, PSE submitted for the Washington Commission's review and approval a Supplemental CACAP (Dockets No. UE-210792 and UG-210793) filing to continue assistance for PSE customers facing financial hardship due to COVID-19. The Washington Commission approved the Supplemental CACAP program to be effective on November 15, 2021. The Supplemental CACAP utilized carry-over funds not expended in any prior years under PSE's Schedule 129 Home Energy Lifeline Program (HELP), with a combined total budget of $34.5 million for both electric and natural gas residential customers (capped at $23.7 million and $10.8 million, respectively). Supplemental CACAP benefits offered to cover a qualifying residential customer's past due balance, up to $2,500. PSE applied the Supplemental CACAP benefits automatically, with an opt-out option, in December 2021.

For additional information, see Note 4, "Regulation and Rates" in the Combined Notes to Consolidated Financial Statements included in Item 8 of this report.

Access to Debt Capital

PSE relies on access to bank borrowings and short-term money markets as sources of liquidity and longer-term capital markets to fund its utility construction program, to meet maturing debt obligations and other capital expenditure requirements not satisfied by cash flow from its operations or equity investment from its parent, Puget Energy. Neither Puget Energy nor PSE have any debt outstanding whose maturity would accelerate upon a credit rating downgrade. However, a ratings downgrade could adversely affect the Company's ability to refinance existing or issue new long-term debt, obtain access to new or renew existing credit facilities and could increase the cost of issuing long-term debt and maintaining credit facilities. For example, under Puget Energy's and PSE's credit facilities, the borrowing costs increase as their respective credit ratings decline due to increases in credit spreads and commitment fees. If PSE is unable to access debt capital on reasonable terms, its ability to pursue improvements or generating capacity acquisitions, which may be relied on for future growth and to otherwise implement its strategy, could be adversely affected. PSE monitors the credit environment and expects to continue to be able to access the capital markets to meet its short-term and long-term borrowing needs. For additional information, see "Financing Program" included in Item 7 of this report.

Regulatory Compliance Costs and Expenditures

PSE's operations are subject to extensive federal, state and local laws and regulations. These regulations cover electric system reliability, natural gas pipeline system safety and energy market transparency, among other areas. Environmental laws and regulations related to air and water quality, including climate change and endangered species protection, waste handling and disposal (including generation by-products such as coal ash), remediation of contamination and siting new facilities also impact the Company's operations. PSE must spend a significant amount of resources to fulfill requirements set by regulatory agencies, many of which have greatly expanded mandates on measures including resource planning, remediation, monitoring, pollution control equipment and emissions-related abatement and fees.

In 2021, the Washington Legislature adopted the Climate Commitment Act (CCA), which establishes a greenhouse gases (GHG) emissions cap-and-invest program that caps GHG emissions beginning on January 1, 2023 and makes further reductions to the cap annually through 2050. The Washington Department of Ecology (WDOE) published final regulations to implement the program on September 29, 2022, which became effective on October 30, 2022. WDOE also indicated that they will have subsequent rulemakings that will build off initial rulemaking as program implementation gets underway and progress with Washington State carbon goals are evaluated. See Part I Item 1 "Recent and Future Environmental Law and Regulation" in this report for further details on the CCA. Based on the rules passed in 2022, there is potential for PSE's compliance with the CCA to result in increased costs to customers or amounts that PSE may not be able to recover through electric and natural gas rates. Potential risks associated with CCA compliance could include: the evolving nature of the CCA rulemaking as indicated by

WDOE, market uncertainty based on rule interpretation during implementation, unresolved recovery methodology for CCA's impact on energy costs, company costs, customer rate impacts, and cash, liquidity and credit volatility.

Compliance with these or other future regulations, such as those pertaining to climate change, could require significant capital expenditures by PSE and may adversely affect PSE's financial position, results of operations, cash flows and liquidity.

Other Challenges and Strategies

Competition

PSE's electric and natural gas utility retail customers generally do not have the ability to choose their electric or natural gas supplier; therefore, PSE's business has historically been recognized as a natural and regulated monopoly. However, PSE faces competition from public utility districts and municipalities or efforts by citizens organizing to form such entities that want to establish their own government-owned utility, as a result of which PSE may lose a number of customers. PSE also faces increasing competition for sales to its retail customers through alternative methods of electric energy generation, including solar and other self-generation methods. In addition, PSE's natural gas customers may elect to use heating oil, propane or other fuels instead of using and purchasing natural gas from PSE.

Results of Operations

Puget Sound Energy

The following discussion should be read in conjunction with the audited consolidated financial statements and the related notes included elsewhere in this document. The following discussion provides the significant items that impacted PSE's results of operations for the years ended December 31, 2022, and December 31, 2021.

Non-GAAP Financial Measures – Electric and Natural Gas Margins

The following discussion includes financial information prepared in accordance with GAAP, as well as two other financial measures, electric margin and natural gas margin, that are considered "non-GAAP financial measures." Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that includes adjustments that result in a presentation that is not defined by GAAP. The presentation of electric margin and natural gas margin is intended to supplement an understanding of PSE's operating performance. Electric margin and natural gas margin are used by PSE to determine whether PSE is collecting the appropriate amount of revenue from its customers in order to provide adequate recovery of operating costs, including interest and equity returns. PSE's electric margin and natural gas margin measures may not be comparable to other companies' electric margin and natural gas margin measures. Furthermore, these measures are not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

The following table presents operating income and a reconciliation of utility electric and natural gas margins to the most directly comparable GAAP measure, operating income:

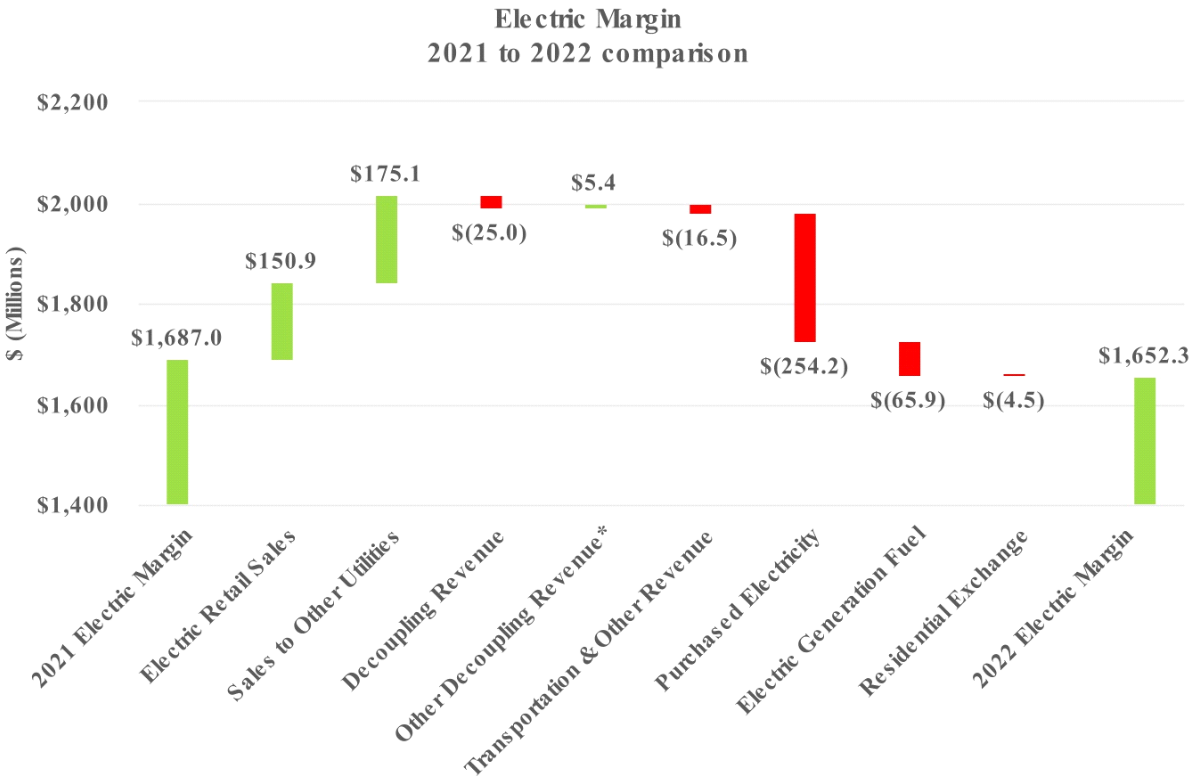
Puget Sound Energy

(Dollars in Thousands)	Year Ended December 31, 2022	2021
Operating income (loss)	$ 792,462	$ 580,147
Electric utility revenue	2,961,457	2,671,623
Purchased electricity	(1,038,728)	(784,565)
Electric generation fuel	(348,159)	(282,254)
Residential exchange	77,715	82,225
Utility electric margin (non-GAAP)	$ 1,652,285	$ 1,687,029
Natural gas operating revenue	$ 1,209,636	$ 1,067,418
Purchased natural gas	(500,849)	(398,553)
Utility natural gas margin (non-GAAP)	$ 708,787	$ 668,865
Other revenue	$ 45,080	$ 66,620
Unrealized gain (loss) on derivative instruments, net	261,177	13,785
Other operation and maintenance expenses	(665,259)	(629,864)
Non-utility expense and other	(47,194)	(56,242)
Depreciation and amortization	(774,291)	(807,519)
Taxes other than income tax expense	(388,123)	(362,527)
Operating income (loss)	$ 792,462	$ 580,147

Electric Margin

Electric margin represents electric sales to retail and transportation customers less the cost of generating and purchasing electric energy sold to customers, including transmission costs to bring electric energy to PSE's service territory.

The following chart displays the changes in PSE's electric margin for the years ended December 31, 2021, to December 31, 2022:



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* *Includes decoupling cash collections, rate of return excess earnings, and decoupling 24-month revenue reserve.*

2021 compared to 2022

Electric Operating Revenue

Electric operating revenues increased $289.8 million primarily due to increased retail sales of $150.9 million, sales to other utilities and marketers of $175.1 million, and other decoupling revenue of $5.4 million; partially offset by a decrease in decoupling revenue of $25.0 million and transportation and other revenue of $16.5 million. These items are discussed in detail below:

- **Electric retail sales** increased $150.9 million due to an increase of $85.2 million in rates compared to the prior year and an increase of $65.7 million from an increase in retail electricity usage of 2.7%. The increase in rates is primarily due to the tariffs filed pursuant to the Company's 2021 PCORC effective July 1, 2021 and the conservation service rider effective May 1, 2022. See Management's Discussion and Analysis, "Regulation of PSE Rates and Recovery of PSE Costs" included in Item 7 of this report for rate changes. The increase in retail usage was due to an increase in residential and commercial usage of 2.4% and 3.3%, respectively. Residential usage increased due to a 5.5% increase in heating degree days due to lower than normal temperatures, primarily in the 2nd quarter of 2022 and a 6.6% increase in cooling degree days due to higher than normal temperatures, primarily in the 3rd quarter of 2022. The increase in commercial usage was driven by employees returning to work after business shut downs and lack of staffing in 2021 due to COVID-19.

- **Sales to other utilities and marketers** increased $175.1 million primarily due to a 109.6% increase in electric wholesale sale price driven by a nationwide increase in natural gas price, that fuel natural gas-fired electric generation, following worldwide natural gas supply constraints along with increased demand from overseas markets. Additionally, wholesale sale volumes increased 1.8%.
- **Decoupling revenue** decreased $25.0 million, primarily attributable to a $7.7 million and $17.3 million decrease in delivery and fixed production cost (FPC) deferral revenues, respectively. This was driven mainly by lower allowed revenue per customer and increased usage for delivery deferral revenues as well as increased usage for FPC deferral revenues. This resulted in allowed revenues being lower than actual decoupling deferral revenues by a greater margin in the current year compared to the prior year.
- **Other decoupling revenue** increased $5.4 million, primarily due to the amortization of prior year residential delivery overcollections beginning in May 2022. This was partially offset by a $2.0 million decrease related to GAAP alternative revenue program recognition guidelines. As of the year ended December 31, 2021, there were $8.0 million of deferred 2020 GAAP alternative decoupling revenues that were recognized, which was partially offset by $3.0 million in deferred 2021 GAAP alternative decoupling revenues. As of the year ended December 31, 2022, there were $3.0 million of deferred 2021 GAAP alternative decoupling revenues that were recognized.
- **Transportation and other revenue** decreased $16.5 million primarily due to no production tax credit (PTC) deferral revenue for the re-purpose of the

PTCs in 2022 compared to $45.6 million in 2021 and a decrease of $32.6 million related to the IRS PLR which includes revenue recognition in 2021, see Management's Discussion and Analysis, "Regulation of PSE Rates and Recovery of PSE Costs" included in Item 7 of this report. The decreases were partially offset by an increase in net wholesale non-core natural gas sales of $62.1 million, which was primarily due to a $130.8 million increase in wholesale sales driven by a 2.8% increase in gas sales volume at an average price that was 71.8% higher in 2022 compared to 2021 and a $107.7 million increase in the cost of gas sold, which was also due to a higher average price and increased volumes. Additionally, the increase in the net whole non-core gas sales was also driven by a $39.0 million increase in gas financial hedging gains.

Electric Power Costs

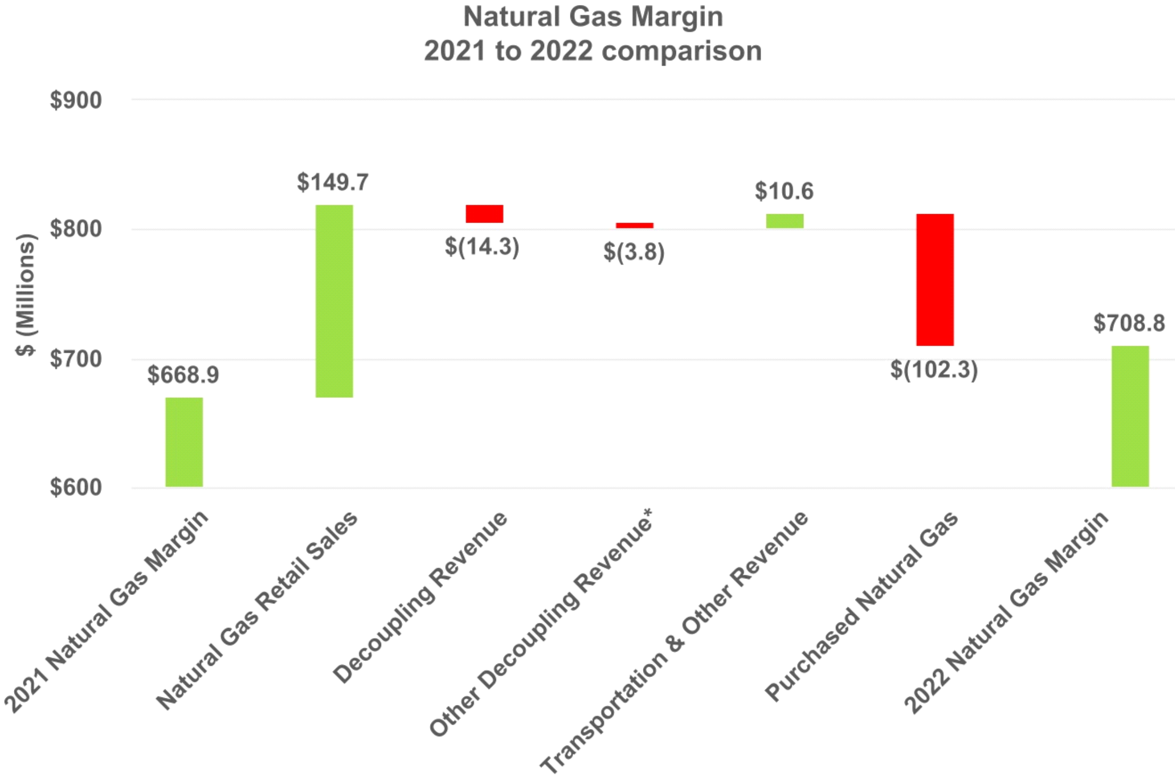
Electric power costs increased $324.6 million primarily due to an increase of $254.2 million of purchased electricity costs, $65.9 million of electric generation fuel costs and a decrease in residential exchange credits of $4.5 million. These items are discussed in detail below:

- **Purchased electricity** expense increased $254.2 million due to a 17.0% increase in wholesale electric purchase volumes and a 13.0% increase in average wholesale purchase prices. The increase in volume was driven by a 25.8% increase in Mid-Columbia hydro, increased wind purchase volumes from Golden Hills and Clearwater, which commenced operations in 2022, and Powerex energy purchases that were added in 2022. Purchase volumes increased due to a combination of an increase in load of 1.8% and a decrease in natural gas-fired generation volume of 17.5%, due to lower market heat rates as natural gas prices increased at a higher rate than power prices. The increase in wholesale purchase prices of 13.0% was primarily due to the aforementioned increase in nationwide natural gas prices, which led to increases in all power prices.
- **Electric generation fuel** expense increased $65.9 million driven by an $8.1 million increase in Colstrip Units 3 and 4 variable fuel expense due to a 6.1% increase in coal fuel burned and a 12.0% increase in the average price per ton. Additionally, natural gas-fired generation fuel costs increased $57.6 million as unit production costs were 51.2% higher due to higher natural gas prices, as discussed above in sales to other utilities. This increase was partially offset by a 17.5% reduction in natural gas-fired generation volumes driven by lower market heat rates.
- **Residential exchange** credits decreased by $4.5 million due to a 0.4% change in the amount of credits to be passed back to customers effective November 1, 2021, see Management's Discussion and Analysis, "Regulation of PSE Rates and Recovery of PSE Costs" included in Item 7 of this report; partially offset by an increase in residential usage of 2.4% as discussed above in electric retail sales.

Natural Gas Margin

Natural gas margin is natural gas sales to retail and transportation customers less the cost of natural gas purchased, including transportation costs to bring natural gas to PSE’s service territory. The PGA mechanism passes through increases or decreases in the natural gas supply portion of the natural gas service rates to customers based upon changes in the price of natural gas purchased from producers and wholesale marketers or changes in natural gas pipeline transportation costs. PSE's margin or net income is not affected by changes under the PGA mechanism because over- and under- recoveries of natural gas costs included in baseline PGA rates are deferred and either refunded or collected from customers, respectively, in future periods.

The following chart displays the changes in PSE’s natural gas margin for the years ended December 31, 2021, to December 31, 2022:



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* *Includes decoupling cash collections, rate of return excess earnings, and decoupling 24-month revenue reserve.*

<u>2021 compared to 2022</u>

Natural Gas Operating Revenue

Natural gas operating revenue increased $142.2 million primarily due to higher retail sales of $149.7 million and transportation and other revenue of $10.6 million. This increase was partially offset by decreased decoupling revenue of $14.3 million and other decoupling revenue of $3.8 million. These items are discussed in the following details:

- **Natural gas retail sales** increased $149.7 million due to an increase in rates of $92.8 million and an increase in natural gas load of 5.2% or $56.9 million of natural gas sales. The increase in rates is due to the tariffs filed pursuant to the Company's most recent CRM and PGA effective November 1, 2021 and Conservation rider effective May 1, 2022, see Management's Discussion and Analysis, "Regulation of PSE Rates and Recovery of PSE Costs" included in Item 7 of this report for natural gas rate changes. The increase in load is driven by an increase of commercial and residential usage of 9.2% and 3.5%, respectively. The increase in commercial usage was largely due to employees returning to work after business shut downs and lack of staffing in 2021 due to COVID-19. Residential usage

increased due to an 5.5% increase in heating degree days due to lower than normal temperatures, primarily in the 2nd quarter of 2022.
- **Decoupling revenue** decreased $14.3 million, primarily attributable to increased usage in 2022 and lower allowed revenue per customer compared to 2021. This resulted in actual natural gas revenues being higher than allowed natural gas revenues in the current period, whereas in 2021, actual revenues were lower than allowed revenues.
- **Other decoupling revenue** decreased $3.8 million due to an increase in current period amortization of prior year revenues compared to 2021. This is attributable to increased usage in 2022 as well as increased amortization rates, both of which increase the rate at which deferral revenues are recovered from customers.
- **Transportation and other revenue** increased $10.6 million primarily due to LNG return deferral revenue of $18.9 million which started in 2022; partially offset by a decrease of $6.2 million related to the IRS PLR which included revenue recognition in 2021 and amortization of the PLR to offset recovery through rates in 2022, see Management's Discussion and Analysis, "Regulation of PSE Rates and Recovery of PSE Costs" included in Item 7 of this report.

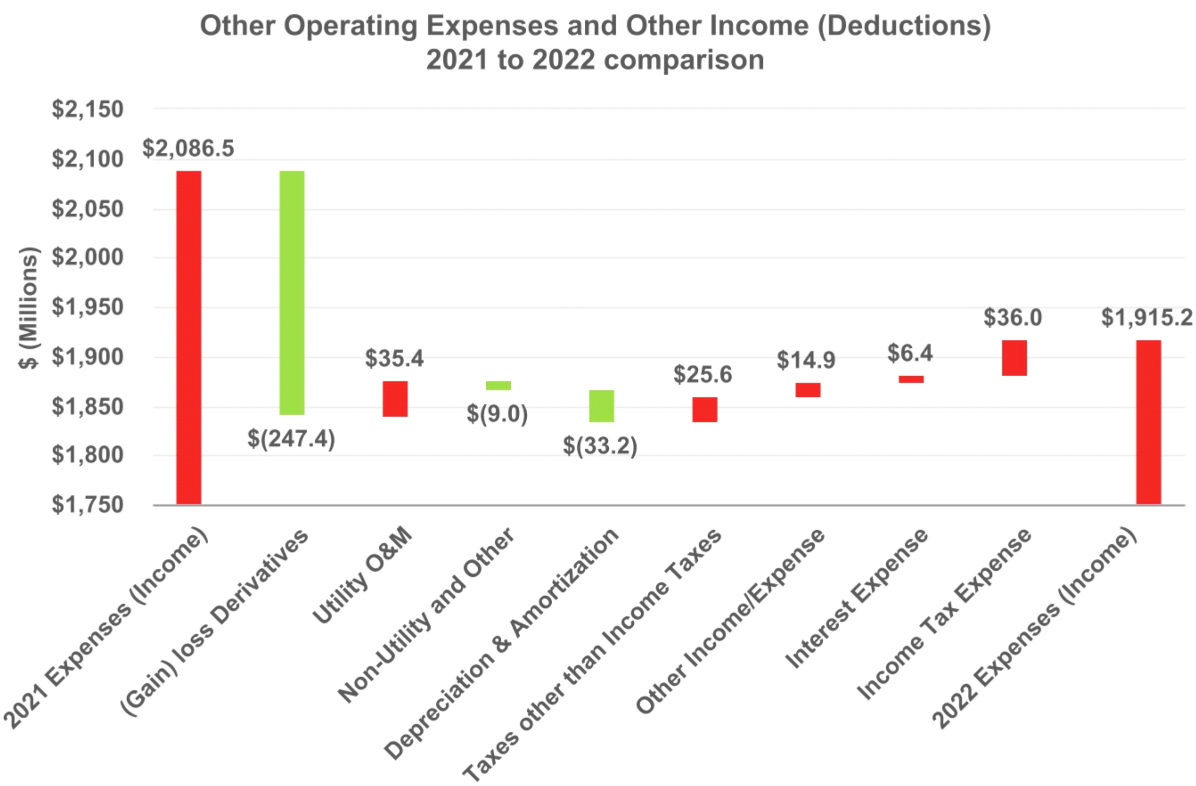
Natural Gas Energy Costs

Purchased natural gas expense increased $102.3 million due to an increase in the PGA rates in November 2021 and an increase in natural gas usage of

5.2% as stated in the natural gas retail sales section above.

Other Operating Expenses and Other Income (Deductions)

The following chart displays the details of PSE's other operating expenses and other income (deductions) for the years ended December 31, 2021, to December 31, 2022:



__**2021 compared to 2022**__

Other Operating Expenses

- **Net unrealized (gain) loss on derivative instruments** increased $247.4 million to a net gain of $261.2 million for the year ended December 31, 2022. The primary driver was the change in the weighted average forward prices for electric and natural gas. Specifically, electric prices increased 128.1% resulting in $236.3 million in gain for electric. Natural gas prices increased 5.3% resulting in $117.1 million in gain for natural gas. These gains were partially offset by the net settlement of electric trades that were previously recorded as $24.0 million in gain and natural gas trades previously recorded as $82.0 million in gain.
- **Utility Operations and Maintenance** expense increased $35.4 million primarily due to increases of (i) $9.8 million in customer service expenses primarily driven by increased low income assistance; (ii) $6.2 million increase in the non-service cost component of the qualified pension net periodic benefit cost in 2022 compared to 2021; (iii) $5.3 million of other generation maintenance costs due to increased wind turbine maintenance; (iv) $5.0 million in administrative and general expenses due to additional vice presidents, incentive and merit increases and IT costs related to technology growth and resumption of training and travel expenses in 2022 compared to 2021; (v) $4.8 million in Washington Commission filing fees related to GRC filings; and (vi) $2.4 million in miscellaneous distribution operations expenses due to training costs specific to electric operations.
- **Non-utility and other** expense decreased $9.0 million primarily due to $12.9 million expenses associated with a 2021 PWI land sale, which was comprised of $11.0 million for the cost of the sale and $1.9 million of selling expenses. This decrease was partially offset by an increase of $3.9 million related to biogas purchase expense.

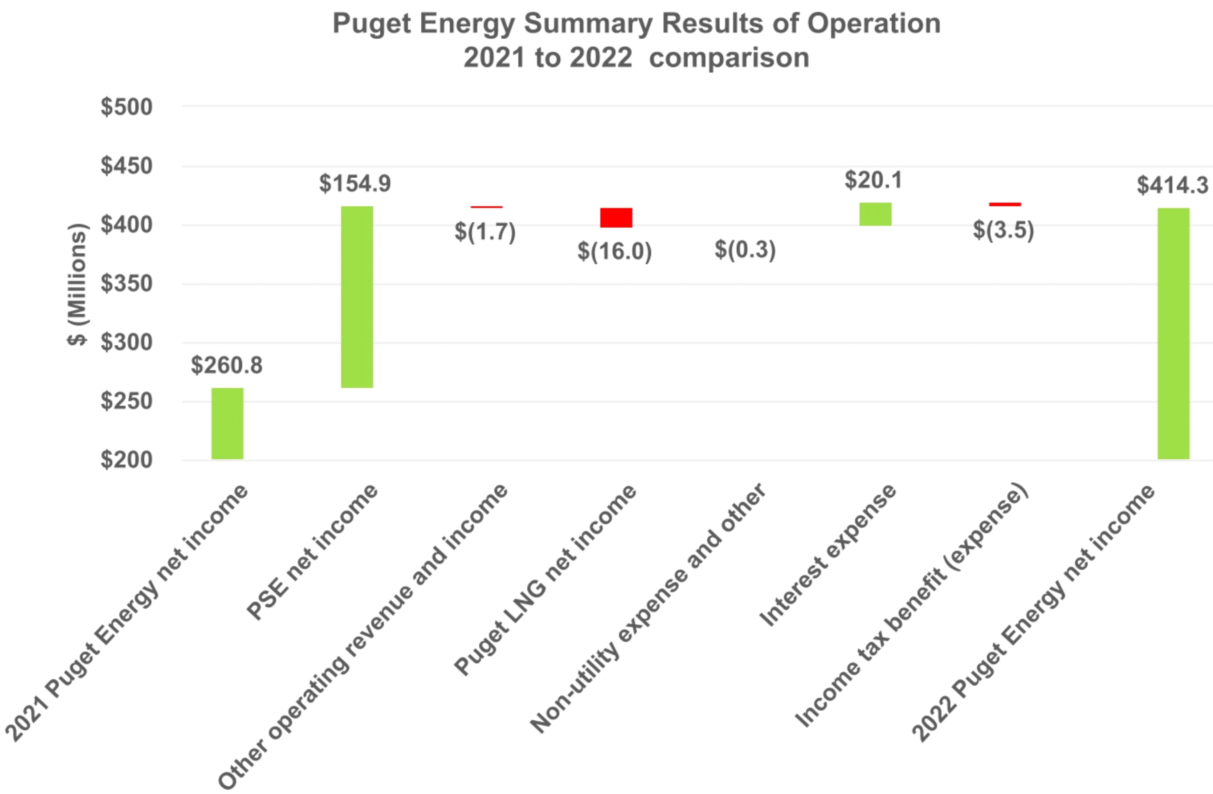
- **Depreciation and amortization** expense decreased $33.2 million primarily driven by: (i) electric amortization decreased by $45.5 million or 51.7% from 2021, primarily driven by $45.6 million less Production Tax Credit (PTC) amortization in 2022 as PSE fully utilized its PTC balance in 2021; (ii) common amortization decreased by $18.4 million or 20.6% from 2021, primarily driven by $25.1 million in net retirements of common technology assets. The Company invested heavily in technology solutions from 2017 - 2019, with a majority of useful lives between 3-5 years; and (iii) natural gas amortization decreased by $6.9 million or 41.6% from 2021, primarily driven by the $5.5 million LNG depreciation expense deferral combined with net retirements of $20.1 million in natural gas technology assets. The decreases were partially offset by (i) conservation amortization increased by $13.8 million due to conservation rider rates effective May 1, 2022, see Management's Discussion and Analysis, "Regulation of PSE Rates and Recovery of PSE Costs" included in Item 7 of this report; (ii) natural gas distribution depreciation increased by $10.7 million or 8.5% from 2021, primarily due to $242.0 million in LNG net additions combined with $175.2 million in net additions in gas distribution assets; (iii) electric distribution depreciation increased a net of $6.4 million or 4.2% from 2021, primarily due to $267.1 million in net additions of electric distribution assets; (iv) electric production depreciation increased a net of $3.3 million or 2.4% from 2021, primarily due to $19.2 million in net additions of electric production assets; and (v) common general plant depreciation increased a net of $2.7 million or 9.6% from 2021, primarily due to $42.1 million in general plant additions offset by $45.0 million in retirements.
- **Taxes other than income taxes** increased $25.6 million primarily due to an increase of $13.8 million related to municipal taxes driven by the increase in retail revenue in 2022 as compared to 2021 and $10.1 million related to the state excise tax.

Other Income, Interest Expense and Income Tax Expense

- **Other income/expense** decreased $14.9 million from net other income of $32.0 million in 2021 to $17.1 million in 2022. The decrease was primarily driven by (i) $7.1 million other income decrease due to a change in AMI return deferral per the 2022 GRC; (ii) $6.8 million other income decrease related to the deferred return for Puget LNG, per Washington Commission Docket No. UG-210918; (iii) $3.2 million other expense increase in non-utility write-offs driven by the Colstrip dry ash facilities exclusion from recovery in rate base per the 2022 GRC; and (iv) $3.1 million other income decrease in Washington Commission allowance for funds used during construction (AFUDC) due to a decrease in Washington Commission AFUDC rates in the first nine months of 2022 compared to 2021. These increases were partially offset by (i) a decrease of $6.2 million in the non-service cost component of the qualified pension net periodic benefit cost for 2022 compared to 2021.
- **Interest expense** increased $6.4 million primarily due to an increase of $9.2 million related to the PSE $450.0 million senior secured notes issued on September 15, 2021. This increase was partially offset by a decrease of $2.9 million related to interest expense recognized in conjunction with PSE's deferred compensation liability.
- **Income tax expense** increased $36.0 million primarily driven by an increase in pre-tax book income.

<u>Puget Energy</u>

Substantially all the operations of Puget Energy are conducted through its regulated subsidiary, PSE. Puget Energy’s results of operation for the years ended December 31, 2021, and December 31, 2022, were as follows:



<u>2021 compared to 2022</u>

Summary Results of Operations

Puget Energy’s net income increased by $153.6 million, which is primarily attributable to an increase in PSE's net income of $154.9 million and a decrease in interest expense of $20.1 million which is a result of lower interest rates on outstanding debt as Puget Energy repaid $500.0 million of 6.00% notes and issued $500.0 million of senior secured notes at an interest rate of 2.379% in June 2021; and Puget Energy repaid $450.0 million 5.625% notes in April 2022 and issued $450.0 million 4.224% notes in March 2022. Additionally, Puget Energy repaid a $210.0 million term loan in June 2021. For further details, see Note 7, "Long-Term Debt" to the consolidated financial statements included in Item 8 of this report. These increases were partially offset by an increase in net loss of $16.0 million at PLNG due to additional operational expenses as PLNG commenced commercial operations in February 2022 and a decrease in income tax benefit of $3.5 million due to an increase in taxable income.

Capital Resources and Liquidity

Capital Requirements

Contractual Obligations and Commercial Commitments

The following are PSE's and Puget Energy's aggregate contractual obligations as of December 31, 2022:

	Payments Due Per Period				
(Dollars in Thousands)	Total	2023	2024-2025	2026-2027	Thereafter
Contractual obligations:					
Energy purchase obligations[1]	$ 8,193,734	$ 2,184,488	$ 2,180,363	$ 1,084,780	$ 2,744,103
Long-term debt including interest[2]	9,014,396	239,716	496,376	774,979	7,503,325
Short-term debt including interest	357,000	357,000	—	—	—
Service contract obligations	416,055	84,095	165,553	86,752	79,655
Non-cancelable operating leases[3]	284,283	23,676	45,119	42,519	172,969
PSE finance leases[3]	142,468	6,383	12,942	13,261	109,882
Pension and other benefits funding and payments	59,961	22,444	11,249	14,960	11,308
Total PSE contractual cash obligations	18,467,897	2,917,802	2,911,602	2,017,251	10,621,242

Long-term debt including interest[2]	2,591,430	156,453	535,066	149,406	1,750,505
Total Puget Energy contractual cash obligations	$ 21,059,327	$ 3,074,255	$ 3,446,668	$ 2,166,657	$ 12,371,747

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1. *Energy purchase contracts were entered into as part of PSE's obligation to serve retail electric and natural gas customers' energy requirements. As a result, costs are generally recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost adjustment mechanisms. Total energy purchase obligation as of December 31, 2022 does not include the Chelan PUD power purchase agreement that was executed on February 7, 2023. For additional information, see Note 16, "Commitments and Contingencies" to the consolidated financial statements included in Item 8 of this report.*
2. *For individual long-term debt maturities, see Note 7, "Long-Term Debt," to the consolidated financial statements included in Item 8 of this report. For Puget Energy, the amount above excludes the fair value adjustments related to the merger.*
3. *For additional information, see Note 9, "Leases" to the consolidated financial statements included in Item 8 of this report.*

The following are PSE's and Puget Energy's aggregate availability under commercial commitments as of December 31, 2022:

	Amount of Available Commitments Expiration Per Period				
(Dollars in Thousands)	Total	Less than 1 Year	1-3 Years	3-5 Years	Thereafter
Commercial commitments:					
PSE revolving credit facility[1]	$ 800,000	$ —	$ —	$ 800,000	$ —
Inter-company short-term debt[2]	30,000	—	—	—	30,000
Total PSE commercial commitments	830,000	—	—	800,000	30,000
Puget Energy revolving credit facility[3]	681,400	—	—	681,400	—
Less: Inter-company short-term debt elimination[2]	(30,000)	—	—	—	(30,000)
Total Puget Energy commercial commitments	$ 1,481,400	$ —	$ —	$ 1,481,400	$ —

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1. *As of December 31, 2022, PSE had a credit facility which provides $800.0 million of short-term liquidity needs and includes a backstop to the Company's commercial paper program. The credit facility matures in May 2027. The credit facility also includes a swingline feature allowing same day availability on borrowings up to $75.0 million and an expansion feature that, upon the banks' approval, would increase the total size of the facility to $1.4 billion. As of December 31, 2022, no loans or letters of credit were outstanding under the credit facility and $357.0 million was outstanding under the commercial paper program. The credit agreement is syndicated among numerous lenders. Outside of the credit agreement, PSE has a $2.3 million letter of credit in support of a long-term transmission contract and had $28.0 million issued under a standby letter of credit in support of natural gas purchases.*
2. *As of December 31, 2022, PSE had a revolving credit facility with Puget Energy in the form of a promissory note to borrow up to $30.0 million.*
3. *As of December 31, 2022, Puget Energy had a revolving senior secured credit facility totaling $800.0 million, which matures in May 2027. The revolving senior secured credit facility is syndicated among numerous lenders. The revolving senior secured credit facility also has an expansion feature that, upon the banks' approval, would increase the size of the facility to $1.3 billion. As of December 31, 2022, there was $118.6 million drawn and outstanding under the Puget Energy credit facility, of which $34.3 million was classified as long-term debt and $84.3 million was classified as short-term debt.*

Off-Balance Sheet Arrangements

As of December 31, 2022, the Company had no off-balance sheet arrangements that have or are reasonably likely to have a material effect on the Company's financial condition.

Utility Construction Program

The Company's construction programs for generating facilities, the electric transmission system, the natural gas and electric distribution systems and the Tacoma LNG facility are designed to meet regulatory requirements, support customer growth and to improve energy system reliability. The Company's capital expenditures were $18.6 million higher than forecasted amounts for 2022. The increase was primarily due to (i) higher storm and weather related outage & emergent response; (ii) accelerated thermal generation maintenance and (iii) technology expenditures related to compliance with the Climate Commitment Act, project management, and check-processing software. Construction expenditures, excluding equity allowance for funds used during construction (AFUDC), totaled $1.0 billion in 2022. Presently planned utility construction expenditures, excluding equity AFUDC, are as follows:

Capital Expenditure Projections			
(Dollars in Millions)	2023	2024	2025
Total energy delivery, technology and facilities expenditures	$1,146.7	$1,311.9	$1,304.2

The program is subject to change based upon general business, economic and regulatory conditions. Utility construction expenditures and any new generation resource expenditures may be funded from a combination of sources, which may include cash from operations, short-term debt, long-term debt and/or equity. PSE's planned capital expenditures may result in a level of spending that will exceed its cash flow from operations. As a result, execution of PSE's strategy is dependent in part on continued access to capital markets.

Capital Resources

Cash from Operations

Puget Sound Energy	Year Ended December 31,		
(Dollars in Thousands)	2022	2021	Change
Net income	$ 490,952	$ 336,063	$ 154,889
Non-cash items[1]	476,696	691,953	(215,257)
Changes in cash flow resulting from working capital[2]	(64,749)	21,379	(86,128)
Regulatory assets and liabilities	(90,335)	(126,625)	36,290
Purchased gas adjustment	37,256	29,720	7,536
Other non-current assets and liabilities[3]	(32,359)	(32,097)	(262)
Net cash (used in)/provided by operating activities	$ 817,461	$ 920,393	$ (102,932)

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1. *Non-cash items include depreciation, amortization, deferred income taxes, net unrealized (gain) loss on derivative instruments, AFUDC-equity, production tax credits and miscellaneous non-cash items.*
2. *Changes in working capital include receivables, unbilled revenue, materials/supplies, fuel/gas inventory, income taxes, prepayments, accounts payable and accrued expenses.*
3. *Other non-current assets and liabilities include funding of pension liability.*

Year Ended December 31, 2022, compared to 2021

Cash generated from operations decreased by $102.9 million, including a net income increase of $154.9 million. The following are significant factors that impacted PSE's cash flows from operations:

- **Cash flow adjustments resulting from non-cash items** decreased $215.3 million primarily due to: (i) a $247.4 million change from a net unrealized gain on derivative instruments of $13.8 million to a net unrealized gain on derivative instruments of $261.2 million, (ii) a decrease in depreciation and amortization of $47.0 million, and (iii) a deferral of return and depreciation expenses for PSE's share of Tacoma LNG investment of $12.1 million. The decreases were partially offset by: (i) a $45.6 million change in PTC utilization, (ii) a $24.5 million change related to recognition of regulatory asset in 2021 as a result of the IRS PLR that concluded the EDIT methodology included in rates following the 2019 GRC order was impermissible, (iii) increased conservation amortization of $13.8 million, and (iv) deferred taxes of $6.5 million. For further discussion, see "Other Operating Expenses" in Item 7, Management's Discussion and Analysis.
- **Cash flows resulting from changes in working capital** decreased $86.1 million primarily due: (i) a cash outflow of $155.8 million in account receivable as its balance increased $252.3 million in the twelve months ended December 31, 2022 compared to an increase of $96.5 million during the same period of 2021; the increase was related to higher wholesale sales of natural gas in November and December of 2022 driven by lower temperatures and higher wholesale prices, (ii) higher balances in materials and supplies and fuel and natural gas inventory increased cash outflows by $23.9 million and $23.1 million respectively, and (iii) increased tax payments of $43.1 million as the result of higher profit in 2022 compared to 2021 and increased Washington state property and utility taxes. The cash outflows were partially offset by (i) an increase in accounts payable of $136.6 million, which was driven by higher sales volumes and increased wholesale energy prices, (ii) higher accrued salary and wages of $7.2 million, (iii) higher short-term accrual for the Supplemental Executive Retirement Plan of $4.7 million, (iv) increased annual Washington Commission filing fee payables of $5.9 million, and (v) lower prepayment balances of $5.2 million.
- **Cash flows resulting from regulatory assets and liabilities** increased $36.3 million primarily due to: (i) a $19.6 million cash inflow was related to changes in deferral of storm excess costs, (ii) a $26.1 million increase in low income program as result of accrued higher cost in 2021 to assist pandemic (COVID-19) affected families, (iii) lower expenses and higher amortization led to an increase of $14.5 million cash inflow in property tax tracker, (iv) amortizing IRS PLR deferral balances contributed an addition of $14.3 million cash inflow, see Management's Discussion and Analysis, "Regulation of PSE Rates and Recovery of PSE Costs" included in Item 7 of this report. The cash inflows were partially offset by a year-over-year change in power cost adjustment receivable, which was relatively flat in 2021, ($3.3 million), and $32.6 million higher in 2022, resulting in a net cash outflow of $35.9 million.

- **Cash flow resulting from purchased gas adjustment** increased $7.5 million, which was driven by an increase in allowed PGA recovery that exceeded the increase in actual gas cost in 2022 compared to 2021. Increased natural gas prices and higher sales volume led to a $93.1 million increase in actual gas costs in 2022 compared to 2021. Meanwhile, the total amount of allowed PGA recovery in 2022 increased $100.6 million compared to 2021. The combined effect led to year-over-year cash inflow.

Puget Energy	Year Ended December 31,		
(Dollars in Thousands)	2022	2021	Change

Net income	$ (76,607)	$ (75,214)	$ (1,393)
Non-cash items[1]	36,689	18,312	18,377
Changes in cash flow resulting from working capital[2]	1,355	(26,229)	27,584
Other non-current assets and liabilities[3]	(9,280)	(10,664)	1,384
Net cash (used in)/provided by operating activities	$ (47,843)	$ (93,795)	$ 45,952

1. *Non-cash items include depreciation, amortization, deferred income taxes, net unrealized (gain) loss on derivative instruments, (Gain) or loss on extinguishment of debt, AFUDC-equity, production tax credits and other miscellaneous non-cash items.*
2. *Changes in working capital include receivables, unbilled revenue, materials/supplies, fuel/gas inventory, income taxes, prepayments, accounts payable and accrued expenses.*
3. *Other non-current assets and liabilities include funding of pension liability.*

Year Ended December 31, 2022, compared to 2021

Cash generated from operations for the year ended December 31, 2022, in addition to the changes discussed at PSE above, increased by $46.0 million compared to the same period in 2021, which includes a net income decrease of $1.4 million. The remaining change was primarily impacted by the factors explained below:

- **Non-cash items** increased $18.4 million primarily due to an increase of $12.6 million in deferred taxes and an increase in amortization and depreciation of $5.5 million.
- **Changes in cash flow resulting from working capital** increased $27.6 million primarily due to: (i) a $13.8 million increase due to the change in PSE's intercompany account receivable and account payable balances with Puget LNG and Puget Energy, which are eliminated upon consolidation of Puget Energy, (ii) changes in tax payable added $15.1 million cash inflow, (iii) cash inflow of $3.5 million driven by reduction of accrued interest expense as result of lower interest rates on debt, as Puget Energy repaid $500.0 million of 6.00% notes and issued $500.0 million of senior secured notes at an interest rate of 2.379% in June, 2021. Additionally, Puget Energy used an equity contribution from Puget Equico to pay off a $210.0 million term loan in June, 2021. The cash inflows were partially offset by cash outflow of $3.9 million as result of Puget LNG commenced commercial operations in February 2022 and accrued $3.9 million in account receivable as of December 31, 2022.

Financing Program

The Company's external financing requirements principally reflect the cash needs of its construction program, its schedule of maturing debt and certain operational needs. The Company anticipates refinancing the redemption of bonds or other long-term borrowings with its credit facilities and/or the issuance of new long-term debt. Access to funds depends upon factors such as Puget Energy's and PSE's credit ratings, prevailing interest rates and investor receptivity to investing in the utility industry, Puget Energy and PSE. The Company believes it has sufficient liquidity through its credit facilities and access to capital markets to fund its needs over the next twelve months.

Proceeds from PSE's short-term borrowings and sales of commercial paper are used to provide working capital and the interim funding of utility construction programs. Puget Energy and PSE continue to have reasonable access to the capital and credit markets.

Proceeds from PSE's short-term borrowings and sales of commercial paper are used to provide working capital and the interim funding of utility construction programs. Puget Energy and PSE continue to have reasonable access to the capital and credit markets. As a result of the prolonged economic stresses of the COVID-19 pandemic and recent inflationary pressures, the company continues to closely monitor cash receipts from customers and any impacts on the Company's liquidity which may affect its ability to fund safe, reliable, and dependable service for our customers.

As a result of the 2019 GRC outcome and the continuing negative impacts of tax reform on the Company's cash flows, Puget Energy and PSE's credit rating metrics were negatively impacted. In response to the 2019 GRC order, Moody's released an issuer comment stating the GRC outcome was credit negative but took no formal credit rating action. On July 23, 2020, S&P placed Puget Energy and PSE on CreditWatch with negative implications due the rate case outcome, but later revised to negative outlook. Fitch affirmed Puget Energy and PSE ratings but changed its outlook from stable to negative. On May 27, 2021, S&P revised Puget Energy's and PSE's ratings from negative to stable outlook. On June 1, 2021, Fitch also revised its outlook for PE and PSE to stable. Both actions were a result of the passage and signing into law of Washington Senate Bill 5295 which allows for multi-year rate plans and reduction of regulatory lag, as well as other actions taken by management to increase revenue via available rate recovery methods and management of internal expenses. Despite these actions, the rating agencies noted that a lack of sufficient regulatory rate relief over the relative near term could result in negative ratings implications. Although neither Puget Energy nor PSE have any debt whose maturity would be accelerated upon a ratings downgrade, a credit rating downgrade may increase the cost of borrowing for Puget Energy and PSE in future long-term financings or under their existing credit facilities. Any increase in the cost of borrowing may negatively impact Puget Energy and PSE's future results of operations and could negatively impact their future liquidity, access to debt capital resources and financial condition. Additionally, a ratings downgrade could impact the Company's ability to issue dividends, see Dividend Payment Restriction below for further details. A downgrade to Puget Energy and PSE's credit ratings would not impact debt covenants under our existing credit facilities nor would it impact other contracts, as neither include credit rating triggering event clauses. A credit rating decrease for PSE could result in increased cash collateral required for commodity contracts, which would adversely affect PSE's liquidity. Management continually monitors the credit rating environment for both Puget Energy and PSE, but cannot predict with certainty the actions credit agencies may take, if any, in response to weaker near term credit metrics, regulatory and rate recovery uncertainties, and management's efforts to contain the growth of capital and operating expenditures. Containing the growth of capital and operating expenditures will be limited, over the near term, due to continuing strategic and risk mitigation imperatives and the necessity of providing safe, reliable and resilient service levels to customers, particularly in the context of the COVID-19 pandemic.

For information on Puget Energy and PSE dividends, long-term debt and credit facilities, see Note 5, “Dividend Payment Restrictions,” Note 7, “Long-term Debt” and Note 8, “Liquidity Facilities and Other Financing Arrangements” to the consolidated financial statements included in Item 8 of this report.

Debt Restrictive Covenants

The type and amount of future long-term financings for PSE may be limited by provisions in PSE's electric and natural gas mortgage indentures.

PSE’s ability to issue additional secured debt may also be limited by certain restrictions contained in its electric and natural gas mortgage indentures. Under the most restrictive tests, at December 31, 2022, PSE could issue:

- Approximately $1.9 billion of additional first mortgage bonds under PSE’s electric mortgage indenture based on approximately $3.2 billion of electric bondable property available for issuance, subject to an interest coverage ratio limitation of 2.0 times net earnings available for interest (as defined in the electric utility mortgage), which PSE exceeded at December 31, 2022; and
- Approximately $1.0 billion of additional first mortgage bonds under PSE’s natural gas mortgage indenture based on approximately $1.7 billion of natural gas bondable property available for issuance, subject to a combined natural gas and electric interest coverage test of 1.75 times net earnings available for interest and a natural gas interest coverage test of 2.0 times net earnings available for interest (as defined in the natural gas utility mortgage), both of which PSE exceeded at December 31, 2022.

At December 31, 2022, PSE had approximately $8.6 billion in electric and natural gas rate base to support the interest coverage ratio limitation test for net earnings available for interest.

Shelf Registrations

On March 10, 2022, Puget Energy filed an S-3 Registration statement under which it may issue up to $1.0 billion aggregate principal amount of senior notes secured by Puget Energy's assets. As of the date of this report, $550.0 million was available to be issued. The shelf registration will expire in March 2025.

In August 2022, PSE filed an S-3 shelf registration statement under which it may issue up to $1.4 billion aggregate principal amount of senior notes secured by first mortgage bonds. As of the date of this report, $1.4 billion was available to be issued. The shelf registration will expire in August 2025.

Critical Accounting Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the reported amounts of assets and liabilities in the financial statements. Management believes the following accounting policies are particularly important to the financial statements and require the use of estimates, assumptions and judgment to describe matters that are inherently uncertain.

Revenue Recognition

Operating utility revenue is recognized when the basis of service is rendered, which includes estimated unbilled revenue. PSE's estimate of unbilled revenue is based on a calculation using meter readings from its automated meter reading system. The estimate calculates unbilled usage at the end of each month as the difference between the customer meter readings on the last day of the month and the last customer meter readings billed during the month less unbilled revenues recorded in the prior month. The "current" month unbilled usage is then priced at published rates for each schedule to estimate the unbilled revenues by customer.

Certain revenues from PSE's electric and natural gas operations are subject to a revenue decoupling mechanism under which PSE's actual energy delivery revenues related to electric transmission and distribution, natural gas operations and general administrative costs are compared with authorized revenues allowed under the mechanism. The mechanism mitigates volatility in revenue due to weather and gross margin erosion related to energy efficiency. Any differences are deferred to a regulatory asset for under recovery or a regulatory liability for over recovery. Revenues associated with power costs under the PCA mechanism and PGA rates are excluded from the decoupling mechanism.

As defined by ASC 980, “Regulated Operations” (ASC 980), the decoupling mechanism is an alternative revenue program that allows billings to be adjusted for the effects of weather abnormalities, conservation efforts or other various external factors. PSE adjusts these billings in the future in response to these effects to collect additional revenues provided under the decoupling mechanism. Once billing of additional revenues under the decoupling mechanism is permitted, the additional revenue can be recognized when the following criteria specified by ASC 980 are met: (i) the program is established by an order from the Washington Commission that allows for automatic adjustment of future rates, (ii) the amount of additional revenues for the period is objectively determinable and is probable of recovery and (iii) the additional revenues will be collected within 24 months following the end of the annual period in which they are recognized. PSE meets the criteria to recognize revenue under the decoupling mechanism. The Company will not record any decoupling revenue that is expected to take longer than 24 months to collect following the end of the annual period in which the revenues would have otherwise been recognized. Once determined to be collectible within 24 months, any previously non-recorded amounts will be recorded.

For further discussion regarding revenue recognition, see Note 3, "Revenue", to the consolidated financial statements included in Item 8 of this report.

Regulatory Accounting

As a regulated entity of the Washington Commission and the FERC, PSE prepares its financial statements in accordance with the provisions of ASC 980. The application of ASC 980 results in differences in the timing and recognition of certain revenue and expenses in comparison with businesses in other industries. The rates that are charged by PSE to its customers are based on cost base regulation reviewed and approved by the Washington Commission and the FERC. Under the authority of these commissions, PSE has recorded certain regulatory assets and liabilities at December 31, 2022, in the amount of $896.4 million and $1,961.1 million, respectively, and regulatory assets and liabilities at December 31, 2021, of $952.5 million and $1,709.5 million, respectively. Such amounts are amortized through a corresponding liability or asset account, respectively, with no impact to earnings. PSE expects to fully recover its regulatory assets and liabilities through its rates. If future recovery of costs ceases to be probable, PSE would be required to write off these regulatory assets and liabilities. In addition, if PSE determines that it no longer meets the criteria for continued application of ASC 980, PSE could be required to write off its regulatory assets and liabilities related to those operations not meeting ASC 980 requirements.

Also encompassed by regulatory accounting and subject to ASC 980 are the PCA and PGA mechanisms. The PCA and PGA mechanisms mitigate the impact of commodity price volatility upon the Company and are approved by the Washington Commission. The PCA mechanism provides for a sharing of costs that vary from baseline rates over a graduated scale. For further discussion regarding the PCA mechanism, see Management's Discussion and Analysis, "Regulation of PSE Rates and Recovery of PSE Costs" included in Item 7 of this report. The increases and decreases in the cost of natural gas supply are reflected in customer bills through the PGA mechanism. PSE expects to fully recover/refund these regulatory balances through its rates. However, both mechanisms are subject to regulatory review and approval by the Washington Commission on a periodic basis.

Derivatives

ASC 815 requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value unless the contracts qualify for an exception. The Company enters into derivative contracts to manage its energy resource portfolio and interest rate exposure including forward physical and financial contracts and swaps. Some of PSE's physical electric supply contracts qualify for the normal purchase normal sale (NPNS) exception to derivative accounting rules. Generally, NPNS applies to contracts with creditworthy counterparties, for which physical delivery is probable and in quantities that will be used in the normal course of business. Power purchases designated as NPNS must meet additional criteria to determine if the transaction is within PSE's forecasted load requirements and if the counterparty owns or controls energy resources within the Western Interconnection to allow for physical delivery of the energy. PSE may enter into financial fixed contracts to economically hedge the variability of certain index-based contracts. Those contracts that do not meet the NPNS exception are marked-to-market to current earnings in the statements of income. Natural gas derivative contracts qualify for deferral under ASC 980 due to the PGA mechanism.

PSE values derivative instruments based on daily quoted prices from an independent external pricing service. The Company regularly confirms the validity of pricing service quoted prices (e.g. Level 2 in the fair value hierarchy) used to value commodity contracts to the actual prices of commodity contracts entered into during the most recent quarter. When external quoted market prices are not available for derivative contracts, PSE uses a valuation model that uses volatility assumptions relating to future energy prices based on specific energy markets and utilizes externally available forward market price curves. All derivative instruments are sensitive to market price fluctuations that can occur on a daily basis. The Company is focused on commodity price exposure and risks associated with volumetric variability in the natural gas and electric portfolios. PSE is not engaged in the business of assuming risk for the purpose of speculative trading. The Company economically hedges open natural gas and electric positions to reduce both the portfolio risk and the volatility risk in prices. The exposure position is determined by using a probabilistic risk system that models 250 simulations of how the Company's natural gas and power portfolios will perform under various weather, hydrological and unit performance conditions.

For additional information, see Item 7A, "Quantitative and Qualitative Disclosures about Market Risk," Note 10, "Accounting for Derivative Instruments and Hedging Activities" and Note 11, "Fair Value Measurements" to the consolidated financial statements included in Item 8 of this report.

Environmental Remediation

The Company is subject to federal and state requirements for protection of the environment, including those for discharge of hazardous materials and remediation of contaminated sites. A potentially responsible party has joint and several liability under existing U.S. environmental laws. In instances where we have been designated a potentially responsible party by the Environmental Protection Agency or state environmental agency, we are potentially liable for the cost of remediating contamination at current work sites and former work sites. Such sites include former manufactured gas plants operated by PSE predecessors, such as Gas Works Park on the shore of Lake Union in Seattle, or contaminated facilities with other connections to PSE predecessors, such as the location of a long-defunct creosote manufacturer which had purchased waste products from PSE predecessors, the Quendall Terminals site on Lake Washington in Renton, Washington. In each case, PSE assesses, based on in-depth studies, expert analyses and legal reviews, our environmental remediation obligations related to contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties and/or insurance carriers. PSE develops a range of reasonably estimable costs that includes a low and high end of a range for all remediation sites for which we have sufficient information. There are some potential remediation obligations where the costs of remediation cannot be reasonably estimated. Liabilities are recorded based on the best estimate or the low end of a range of reasonably possible costs expected to be incurred to remediate sites. It's possible that costs are incurred in excess of the recorded amounts because of changes in laws and/or regulations, higher than expected costs and/or the discovery of new or additional contamination. The Company believes a significant portion of its past and future environmental remediation costs are recoverable from insurance companies, from third parties or from customers under a Washington Commission order.

For additional information see Note 4, "Regulation and Rates" to the consolidated financial statements included in Item 8 of this report.

Fair Value

ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). However, as permitted under ASC 820, the Company utilizes a mid-market pricing convention (the midpoint price between bid and ask prices) as a practical expedient for valuing the majority of its assets and liabilities measured and reported at fair value. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company primarily applies the market approach for recurring fair value measurements as it believes that

this approach is used by market participants for these types of assets and liabilities. Accordingly, the Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. For further discussion on market risk, see Item 7A, "Quantitative and Qualitative Disclosures about Market Risk" in this report.

Pension and Other Postretirement Benefits

PSE has a qualified defined benefit pension plan covering substantially all employees of PSE. PSE recognized qualified pension expense of $14.7 million and $21.4 million for the years ended December 31, 2022, and 2021, respectively. Of these amounts, approximately 48.3% and 48.7% were included in utility operations and maintenance expense in 2022 and 2021, respectively, and the remaining amounts were capitalized. For the years ended December 31, 2022, and 2021, Puget Energy recognized incremental qualified pension income of $8.7 million and $10.4 million, respectively. In 2023, it is expected that PSE and Puget Energy will recognize pension income of $0.4 million and incremental qualified pension income of $3.5 million, respectively.

PSE has a SERP and recognized pension and other postretirement benefit expenses of $4.7 million and $4.3 million for the years ended December 31, 2022, and 2021, respectively. For the years ended December 31, 2022, and 2021, Puget Energy recognized incremental income of $0.2 million and $0.2 million, respectively. In 2023, it is expected that PSE and Puget Energy will recognize pension expense of $2.4 million and incremental pension income of $0.1 million, respectively.

PSE also has other limited postretirement benefit plans. PSE recognized income of $0.1 million and $0.1 million for the years ended December 31, 2022, and 2021, respectively. For the years ended December 31, 2022, and 2021, Puget Energy recognized incremental expense of $0.1 million in both years. In 2023, it is expected that PSE and Puget Energy will recognize expense of $0.1 million and incremental expense of $0.1 million, respectively.

The Company’s pension and other postretirement benefits income or expense depend on several factors and assumptions, including plan design, timing and amount of cash contributions to the plan, earnings on plan assets, discount rate, expected long-term rate of return, mortality and health care cost trends. Changes in any of these factors or assumptions will affect the amount of income or expense that the Company records in its financial statements in future years and its projected benefit obligation. The Company has selected an expected return on plan assets based on a historical analysis of rates of return and the Company’s investment mix, market conditions, inflation and other factors. The Company’s accounting policy for calculating the market-related value of assets is based on a five-year smoothing of asset gains or losses measured from the expected return on market-related assets. This is a calculated value that recognizes changes in fair value in a systematic and rational manner over five years. The same manner of calculating market-related value is used for all classes of assets and is applied consistently from year to year. During 2022, the Company made cash contributions of $18.0 million to the qualified defined pension plan. Management is closely monitoring the funding status of its qualified pension plan. At December 31, 2022, and 2021, the Company’s qualified pension plan was $69.3 million overfunded and $63.6 million overfunded as measured under GAAP, or 111.8% and 107.6% funded, respectively. As of January 1, 2023, the plan's estimated funded ratio, as calculated under guidelines from The Pension Protection Act of 2006 and considering temporary interest rate relief measures approved by Congress, was more than 100%. The aggregate expected contributions and payments by the Company to fund the pension plan, SERP and other postretirement plans for the year ending December 31, 2023, are expected to be at least $18.0 million, $3.5 million and $0.3 million, respectively.

The discount rate used in accounting for pension and other benefit obligations increased from 3.00% in 2021 to 5.60% in 2022. The discount rate used in accounting for pension and other benefit expense increased from 2.70% in 2021 to 3.00% in 2022. The rate of return on plan assets for qualified pension benefits remains unchanged at 6.50% in both 2021 and 2022. The rate of return on plan assets for other benefits was 7.00% in both 2021 and 2022.

The follow tables reflect the estimated sensitivity associated with a change in certain significant actuarial assumptions (each assumption change is presented mutually exclusive of other assumption changes):

Puget Energy and Puget Sound Energy	Change in Assumption	Impact on Projected Benefit Obligation Increase /(Decrease)		
(Dollars in Thousands)		Pension Benefits	SERP	Other Benefits
Increase in discount rate	50 basis points	$ (29,451)	$ (795)	$ (306)
Decrease in discount rate	50 basis points	32,186	840	330

Impact on 2022

Puget Energy	Change in Assumption	Pension Expense Increase /(Decrease)		
(Dollars in Thousands)		Pension Benefits	SERP	Other Benefits
Increase in discount rate	50 basis points	$ (3,672)	$ (241)	$ 4
Decrease in discount rate	50 basis points	3,942	256	(21)
Increase in return on plan assets	50 basis points	$ (3,926)	*	$ (27)
Decrease in return on plan assets	50 basis points	3,925	*	27

Puget Sound Energy	Change in Assumption	Impact on 2022 Pension Expense Increase /(Decrease)		
(Dollars in Thousands)		Pension Benefits	SERP	Other Benefits
Increase in discount rate	50 basis points	$ (3,672)	$ (241)	$ 3
Decrease in discount rate	50 basis points	3,942	256	(16)
Increase in return on plan assets	50 basis points	$ (3,926)	*	$ (27)
Decrease in return on plan assets	50 basis points	3,926	*	27

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* *Calculation not applicable.*

Recently Adopted Accounting Pronouncements

For the discussion of recently adopted accounting pronouncements, see Note 2, "New Accounting Pronouncements" to the consolidated financial statements included in Item 8 of this report.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Energy Portfolio Management

PSE maintains energy risk policies and procedures to manage risks inherent to participating in wholesale energy markets that may have related effects on credit, tax, accounting, financing and liquidity. The nature of operating generation and distribution facilities, obtaining transmission service, securing fuel and other necessary services, and energy market participation generally is such that there is continuous exposure to various risks including market, asset reliability, operational, liquidity, model, and counterparty credit risk. PSE's Energy Risk Management Committee establishes PSE's risk management policies and procedures, and is responsible for reviewing risk tolerances and limits, establishing delegations of authority, maintaining systemic and procedural adequacy of control system, and monitoring compliance. The Energy Risk Management Committee is comprised of certain PSE officers and is overseen by the PSE Board of Directors.

PSE's objective is to minimize commodity price exposure and risks associated with volumetric variability in the natural gas and electric portfolios to ensure physical energy supplies are available to serve retail customer loads while managing portfolio risks to limit undesired impacts and optimizing the capacity value of energy supply assets. It is not engaged in the business of assuming risk for the purpose of speculative trading. PSE hedges open natural gas and electric positions to reduce both the portfolio risk and the volatility risk in prices.

PSE's energy risk portfolio management function monitors and manages these risks using analytical models and tools including a probabilistic risk system that models 250 simulations of how PSE's natural gas and power portfolios will perform under various weather, hydroelectric and unit performance conditions. Based on the analytics from all of its models and tools, PSE enters into forward physical electric and natural gas purchase and sale agreements, fixed-for-floating swap contracts, and commodity options to manage its electric and natural gas portfolio risks. The forward physical electric and natural gas contracts are both fixed and variable (at index). To fix the price of wholesale electricity and natural gas, PSE may enter into fixed-for-floating swap (derivative) contracts. PSE also utilizes natural gas options as an additional hedging instrument to

increase the hedging portfolio's flexibility to react to commodity price fluctuations while also allowing for participation in low price commodity markets.

The following table presents the fair value of the Company's energy derivatives instruments, recorded on the balance sheets:

Puget Energy and Puget Sound Energy	December 31, 2022		December 31, 2021	
(Dollars in Thousands)	Assets	Liabilities	Assets	Liabilities
Electric portfolio:				
Current	$ 267,811	$ 79,668	$ 61,291	$ 50,979
Long-term	69,892	7,452	13,538	34,445

Total Electric Portfolio	$ 337,703	$ 87,120	$ 74,829	$ 85,424
Natural gas portfolio:				
Current	319,218	45,308	66,919	12,330
Long-term	24,729	10,914	12,659	6,520
Total Natural Gas Portfolio	$ 343,947	$ 56,222	$ 79,578	$ 18,850
Total derivatives	$ 681,650	$ 143,342	$ 154,407	$ 104,274

At December 31, 2022, the Company had total assets of $681.7 million and total liabilities of $143.3 million related to derivative contracts used to hedge the supply and cost of electricity and natural gas to serve PSE customers. As the gains and losses in the electric portfolio are realized, they will be recorded as either purchased power costs or electric generation fuel costs under the PCA mechanism. Any fair value adjustments relating to the natural gas business have been deferred in accordance with ASC 980, due to the PGA mechanism, which passes the cost of natural gas supply to customers. As the gains and losses on the hedges are realized in future periods, they will be recorded as natural gas costs under the PGA mechanism.

A hypothetical 10.0% increase or decrease in market prices of natural gas and electricity would change the fair value of the Company's derivative contracts by $85.2 million.

The change in fair value of the Company's outstanding energy derivative instruments from December 31, 2021, through December 31, 2022, is summarized in the table below:

Puget Energy and Puget Sound Energy

Energy Derivative Contracts Gain (Loss) (Dollars in Thousands)	December 31, 2022
Fair value of contracts outstanding at December 31, 2021	$ 50,133
Contracts realized or otherwise settled during 2022	(357,980)
Change in fair value of derivatives	846,155
Fair value of contracts outstanding at December 31, 2022	$ 538,308

The fair value of the Company's outstanding derivative instruments at December 31, 2022, based on pricing source and the period during which the instrument will mature, is summarized below:

Puget Energy and Puget Sound Energy **Source of Fair Value**	Fair Value of Contracts by Settlement Year				
(Dollars in Thousands)	2023	2024-2025	2026-2027	Thereafter	Total
Prices provided by external sources[1]	$ 389,832	$ 33,850	$ (1,325)	$ —	$ 422,357
Prices based on internal models and valuation methods	72,222	35,862	7,867	—	115,951
Total fair value	$ 462,054	$ 69,712	$ 6,542	$ —	$ 538,308

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1. *Prices provided by external pricing service, which utilizes broker quotes and pricing models.*

For further details regarding both the fair value of derivative instruments and the impacts such instruments have on current period earnings, see Note 10, "Accounting for Derivative Instruments and Hedging Activities" and Note 11, "Fair Value Measurements" to the consolidated financial statements included in Item 8 of this report.

Contingent Features and Counterparty Credit Risk

PSE is exposed to credit risk primarily through buying and selling electricity and natural gas to serve customers. Credit risk is the potential loss resulting from a counterparty's non-performance under an agreement. PSE manages credit risk with policies and procedures for, among other things, counterparty analysis and measurement, monitoring and mitigation of exposure.

PSE has entered into commodity master arrangements with its counterparties to mitigate credit exposure to those counterparties. PSE generally enters into the following master arrangements: WSPP, Inc. (WSPP) agreements which standardize physical power contracts in the electric industry; International Swaps and Derivatives Association (ISDA) agreements which standardize financial natural gas and electric contracts; and North American Energy Standards Board (NAESB) agreements which standardize physical natural gas contracts. PSE believes that entering into such agreements reduces the credit risk exposure because such agreements provide for the netting and offsetting of monthly payments as well as right of set-off in the event of counterparty default. It is possible that volatility in energy commodity prices could cause PSE to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, PSE could suffer a material financial loss. In order to mitigate concentrated credit risk with a subset of counterparties, PSE enters into cleared transactions on the Intercontinental Exchange (ICE) for power futures contracts and ICE NGX for natural gas supply contracts.

Where deemed appropriate, and when allowed under the terms of the agreements, PSE may request collateral or other security from its counterparties to mitigate the potential credit default losses. Criteria employed in this decision include, among other things, the perceived creditworthiness of the counterparty and the expected credit exposure. As of December 31, 2022, PSE held approximately $775.8 million in standby letters of credit or limited parental guarantees and had seven counterparties with unlimited parental guarantees, in support of various electric and natural gas transactions. The Company monitors counterparties for significant swings in credit default rates, credit rating changes by external rating agencies, ownership changes or financial distress. As of December 31, 2022, approximately 80.4% of the Company's total energy portfolio exposure was entered into with investment grade counterparties which, in the majority of cases, do not require collateral calls on the contracts. Counterparty credit risk may impact PSE's decisions on derivative accounting treatment.

Should a counterparty file for bankruptcy, which would be considered a default under master arrangements, PSE may terminate related contracts. Derivative accounting entries previously recorded would be reversed in the financial statements. PSE would compute any terminations receivable or payable, based on the terms of existing master agreements. The Company computes credit reserves at a master agreement level by counterparty. The Company considers external credit ratings and market factors, such as credit default swaps and bond spreads, in determination of reserves. The Company recognizes that external ratings may not always reflect how a market participant perceives a counterparty’s risk of default. The Company uses both default factors published by Standard & Poor’s and factors derived through analysis of market risk, which reflect the application of an industry standard recovery rate. The Company selects a default factor by counterparty at an aggregate master agreement level based on a weighted-average default tenor for that counterparty’s deals. The default tenor is determined by weighting the fair value and contract tenors for all deals by counterparty and arriving at an average value. The default factor used is dependent upon whether the counterparty is in a net asset or a net liability position after applying the master agreement levels.

The Company applies the counterparty's default factor to compute credit reserves for counterparties that are in a net asset position. The Company calculates a non-performance risk on its derivative liabilities by using its estimated incremental borrowing rate over the risk-free rate. Credit reserves are netted against unrealized gain (loss) positions. As of December 31, 2022, the Company was in a net asset position with the majority of counterparties, so the default factors of counterparties did not have a significant impact on reserves for the period. The majority of the Company's derivative contracts are with financial institutions and other utilities operating within the Western Electricity Coordinating Council. PSE also transacts power futures contracts on the Intercontinental Exchange (ICE), and natural gas contracts on the ICE NGX platform. Execution of contracts on ICE requires the daily posting of margin calls as collateral through a futures and clearing agent. As of December 31, 2022, PSE had cash posted as collateral of $23.2 million related to contracts executed on the ICE platform. In August 2022, PSE entered into a standby letter of credit agreement with TD Bank allowing standby letter of credit postings of up to $50.0 million as a condition of transacting on the ICE NGX platform. As of December 31, 2022, PSE had $33.0 million in cash posted with ICE NGX and $28.0 million issued under the standby letter of credit agreement. PSE did not trigger any collateral requirements with any of its counterparties nor were any of PSE's counterparties required to post collateral resulting from credit rating downgrades during the twelve months ended December 31, 2022.

Interest Rate Risk

The Company believes its interest rate risk primarily relates to the use of short-term debt instruments, variable-rate leases and anticipated long-term debt financing needed to fund capital requirements. The Company manages its interest rate risk through the issuance of mostly fixed-rate debt of various maturities. The Company utilizes internal cash from operations, borrowings under its commercial paper program, and its credit facilities to meet short-term funding needs. Short-term obligations are commonly refinanced with fixed-rate bonds or notes when needed and when interest rates are considered favorable.

The following table presents the carrying value and fair value of Puget Energy and Puget Sound Energy's long-term debt instruments:

Long-Term Debt Instruments	December 31, 2022		December 31, 2021	
(Dollars in Thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Puget Energy	$ 6,663,373	$ 6,184,097	$ 6,203,766	$ 7,803,196
Puget Sound Energy	4,786,765	4,379,010	4,784,719	6,145,639

For further details regarding Puget Energy and Puget Sound Energy debt instruments, see Note 7, "Long-Term Debt" and Note 11, "Fair Value Measurements" to the consolidated financial statements included in Item 8 of this report.

From time to time, PSE may enter into treasury locks or forward starting swap contracts to hedge interest rate exposure related to an anticipated debt issuance. The ending balance in other comprehensive income (OCI) related to the forward starting swaps and previously settled treasury lock contracts at December 31, 2022, was a net loss of $4.2 million after-tax and accumulated amortization. This compares to an after-tax loss of $4.6 million in OCI as of December 31, 2021. All financial hedge contracts of this type are reviewed by an officer, presented to the Board of Directors, or a committee of the Board, as applicable and are approved prior to execution. PSE had no treasury locks or forward starting swap contracts outstanding at December 31, 2022.

The Company may also enter into swap instruments or other financial hedge instruments to manage the interest rate risk associated with these debts. As of December 31, 2022, the Company had no outstanding interest rate swap instruments.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORTS:

INDEX TO FINANCIAL STATEMENTS:

PUGET ENERGY:

PUGET SOUND ENERGY:

NOTES to the Consolidated Financial Statements of Puget Energy and Puget Sound Energy:

SCHEDULE:

All other schedules have been omitted because of the absence of the conditions under which they are required, or because the information required is included in the consolidated financial statements or the notes thereto.

REPORT OF MANAGEMENT AND STATEMENT OF RESPONSIBILITY

PUGET ENERGY, INC.
AND
PUGET SOUND ENERGY, INC.

Puget Energy, Inc. and Puget Sound Energy, Inc. (the Company) management assumes accountability for maintaining compliance with our established financial accounting policies and for reporting our results with objectivity and integrity. The Company believes it is essential for investors and other users of the consolidated financial statements to have confidence that the financial information we provide is timely, complete, relevant and accurate. Management is also responsible to present fairly Puget Energy's and Puget Sound Energy's consolidated financial statements, prepared in accordance with GAAP.

Management, with oversight of the Board of Directors, established and maintains a strong ethical climate under the guidance of our Corporate Ethics and Compliance Program so that our affairs are conducted to high standards of proper personal and corporate conduct. Management also established an internal control system that provides reasonable assurance as to the integrity and accuracy of the consolidated financial statements. These policies and practices reflect corporate governance initiatives designed to ensure the integrity and independence of our financial reporting processes including:

1. Our Board has adopted clear corporate governance guidelines.
2. With the exception of the President and Chief Executive Officer, the Board members are independent of management.
3. All members of our key Board committees – the Audit Committee, the Compensation and Leadership Development Committee and the Governance and Public Affairs Committee – are independent of management.
4. The non-management members of our Board meet regularly without the presence of Puget Energy and Puget Sound Energy management.
5. The Charters of our Board committees clearly establish their respective roles and responsibilities.
6. The Company has adopted a Code of Conduct with a hotline (through an independent third party) available to all employees, and our Audit Committee has procedures in place for the anonymous submission of employee complaints on accounting, internal accounting controls or auditing matters. The Compliance Program is led by the Chief Ethics and Compliance Officer of the Company.
7. Our internal audit control function maintains critical oversight over the key areas of our business and financial processes and controls, and reports directly to our Board Audit Committee.

Management is confident that the internal control structure is operating effectively and will allow the Company to meet the requirements under Section 404 of the Sarbanes-Oxley Act of 2002.

PricewaterhouseCoopers LLP, our independent registered public accounting firm, reports directly to the Audit Committee of the Board of Directors. PricewaterhouseCoopers LLP's accompanying report on our consolidated financial statements is based on its audit conducted in accordance with auditing standards prescribed by the Public Company Accounting Oversight Board, including a review of our internal control structure for purposes of designing their audit procedures. Our independent registered accounting firm has reported on the effectiveness of our internal control over financial reporting as required under Section 404 of the Sarbanes-Oxley Act of 2002.

We are committed to improving shareholder value and accept our fiduciary oversight responsibilities. We are dedicated to ensuring that our high standards of financial accounting and reporting as well as our underlying system of internal controls are maintained. Our culture demands integrity and we have confidence in our processes, our internal controls and our people, who are objective in their responsibilities and who operate under a high level of ethical standards.

/s/ Mary E. Kipp	/s/ Kazi Hasan	/s/ Stacy Smith
Mary E. Kipp	Kazi Hasan	Stacy Smith
President and Chief Executive Officer	*Executive Vice President and Chief Financial Officer*	*Controller and Principal Accounting Officer*

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Puget Energy, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes and financial statement schedules, of Puget Energy, Inc. and its subsidiaries (the "Company") as listed in the accompanying index (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of Regulatory Matters

As described in Notes 1 and 4 to the consolidated financial statements, the Company recorded $904.3 million of regulatory assets and $2,025.5 million of regulatory liabilities as of December 31, 2022. Management accounts for the Company’s regulated operations in accordance with the Financial Accounting Standards Board’s (FASB) accounting guidance for regulated operations, which requires deferral of certain costs or losses that would otherwise be charged to expense, if it is probable that future rates will permit recovery of such costs. The FASB’s accounting guidance for regulated operations similarly requires deferral of revenues or gains that are expected to be returned to customers in the future. This accounting is appropriate as long as rates are established by or subject to approval by independent third-party regulators; rates are designed to recover the specific enterprise’s cost of service; and in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers. As disclosed by management, the regulatory assets and liabilities are expected to be fully recovered through the Company’s rates. If future recovery of costs ceases to be probable, management would be required to write off the regulatory assets and liabilities. In addition, if management determines that it no longer meets the criteria for continued application of the FASB’s accounting guidance for regulated operations, management could be required to write off its regulatory assets and liabilities related to those operations not meeting the FASB’s requirements.

The principal considerations for our determination that performing procedures relating to the Company’s accounting for the effects of regulatory matters is a critical audit matter is the high degree of effort in performing audit procedures and evaluating audit evidence obtained related to the continued application of regulatory accounting and accounting for regulatory assets and liabilities.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management’s assessment of the continued application of regulatory accounting and management’s review and application of regulatory proceedings. These procedures also included, among others, (i) evaluating the reasonableness of management’s judgments regarding the continued application of regulatory accounting and the probability of recovery of the capital investments and regulatory assets and settlement of regulatory liabilities; (ii) testing existing regulatory assets and liabilities and; (iii) assessing the appropriateness of the disclosures in the consolidated financial statements. Evaluating the continued application of regulatory accounting and the accounting for new and existing regulatory assets and liabilities involved examining the Company’s correspondence with regulators, pending regulatory proceedings, and the provisions and formulas outlined in rate orders to assess the impact on the amounts recognized.

/s/ PricewaterhouseCoopers LLP
Portland, Oregon
February 23, 2023

We have served as the Company’s or its predecessor’s auditor since 1933.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Puget Sound Energy, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes and financial statement schedule, of Puget Sound Energy, Inc. and its subsidiary (the “Company”) as listed in the accompanying index (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of Regulatory Matters

As described in Notes 1 and 4 to the consolidated financial statements, the Company recorded $896.4 million of regulatory assets and $1,961.1 million of regulatory liabilities as of December 31, 2022. Management accounts for the Company's regulated operations in accordance with the Financial Accounting Standards Board's (FASB) accounting guidance for regulated operations, which requires deferral of certain costs or losses that would otherwise be charged to expense, if it is probable that future rates will permit recovery of such costs. The FASB's accounting guidance for regulated operations similarly requires deferral of revenues or gains that are expected to be returned to customers in the future. This accounting is appropriate as long as rates are established by or subject to approval by independent third-party regulators; rates are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers. As disclosed by management, the regulatory assets and liabilities are expected to be fully recovered through the Company's rates. If future recovery of costs ceases to be probable, management would be required to write off the regulatory assets and liabilities. In addition, if management determines that it no longer meets the criteria for continued application of the FASB's accounting guidance for regulated operations, management could be required to write off its regulatory assets and liabilities related to those operations not meeting the FASB's requirements.

The principal considerations for our determination that performing procedures relating to the Company's accounting for the effects of regulatory matters is a critical audit matter is the high degree of effort in performing audit procedures and evaluating audit evidence obtained related to the continued application of regulatory accounting and accounting for regulatory assets and liabilities.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's assessment of the continued application of regulatory accounting and management's review and application of regulatory proceedings. These procedures also included, among others, (i) evaluating the reasonableness of management's judgments regarding the continued application of regulatory accounting and the probability of recovery of the capital investments and regulatory assets and settlement of regulatory liabilities; (ii) testing existing regulatory assets and liabilities and; (iii) assessing the appropriateness of the disclosures in the consolidated financial statements. Evaluating the continued application of regulatory accounting and the accounting for new and existing regulatory assets and liabilities involved examining the Company's correspondence with regulators, pending regulatory proceedings, and the provisions and formulas outlined in rate orders to assess the impact on the amounts recognized.

/s/ PricewaterhouseCoopers LLP
Portland, Oregon
February 23, 2023

We have served as the Company's or its predecessor's auditor since 1933.

PUGET ENERGY, INC.

CONSOLIDATED STATEMENTS OF INCOME

(Dollars in Thousands)

	Year Ended December 31,		
	2022	2021	2020
Operating revenue:			
Electric	$ 2,961,457	$ 2,671,623	$ 2,319,416
Natural gas	1,209,636	1,067,418	980,913
Other	50,069	66,620	26,121
Total operating revenue	4,221,162	3,805,661	3,326,450
Operating expenses:			
Energy costs:			
Purchased electricity	1,038,728	784,565	593,719
Electric generation fuel	348,159	282,254	199,107
Residential exchange	(77,715)	(82,225)	(80,294)
Purchased natural gas	500,849	398,553	362,872
Unrealized (gain) loss on derivative instruments, net	(261,177)	(13,785)	26,807
Utility operations and maintenance	665,259	629,864	597,048
Non-utility expense and other	59,804	58,281	43,425
Depreciation and amortization	663,232	704,783	647,755
Conservation amortization	116,942	103,147	99,585
Taxes other than income taxes	389,442	362,527	328,602
Total operating expenses	3,443,523	3,227,964	2,818,626
Operating income (loss)	777,639	577,697	507,824
Other income (deductions):			
Other income	45,450	57,483	58,759
Other expense	(19,569)	(14,467)	(23,207)
Interest charges:			
AFUDC	18,444	16,743	14,827
Interest expense	(347,921)	(352,092)	(373,822)
Income (loss) before income taxes	474,043	285,364	184,381
Income tax (benefit) expense	59,698	24,515	1,664
Net income (loss)	$ 414,345	$ 260,849	$ 182,717

The accompanying notes are an integral part of the consolidated financial statements.

PUGET ENERGY, INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in Thousands)

	Year Ended December 31,		
	2022	2021	2020
Net income (loss)	$ 414,345	$ 260,849	$ 182,717
Other comprehensive income (loss):			
Net unrealized gain (loss) from pension and postretirement plans, net of tax of $708, $15,686 and $(609), respectively	2,658	59,005	(2,288)
Other comprehensive income (loss)	2,658	59,005	(2,288)
Comprehensive income (loss)	$ 417,003	$ 319,854	$ 180,429

The accompanying notes are an integral part of the consolidated financial statements.

PUGET ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

(Dollars in Thousands)

ASSETS

	December 31,	
	2022	2021
Utility plant (at original cost, including construction work in progress of $861,801 and $870,204, respectively):		
Electric plant	$ 10,300,895	$ 9,729,643
Natural gas plant	4,721,982	4,498,198
Common plant	1,103,783	1,155,567
Less: Accumulated depreciation and amortization	(4,341,789)	(4,031,458)
Net utility plant	11,784,871	11,351,950
Other property and investments:		
Goodwill	1,656,513	1,656,513
Other property and investments	328,535	324,897
Total other property and investments	1,985,048	1,981,410
Current assets:		
Cash and cash equivalents	105,740	56,946
Restricted cash	63,045	46,204
Accounts receivable, net of allowance for doubtful accounts of $41,962 and $34,958, respectively	673,236	398,895
Unbilled revenue	284,022	271,606
Materials and supplies, at average cost	132,172	113,287
Fuel and natural gas inventory, at average cost	94,075	59,393
Unrealized gain on derivative instruments	587,029	128,210
Prepaid expenses and other	41,940	46,293
Power contract acquisition adjustment gain	16,736	17,274
Total current assets	1,997,995	1,138,108
Other long-term and regulatory assets:		
Power cost adjustment mechanism	112,207	79,546
Purchased gas adjustment receivable	—	57,935
Regulatory assets related to power contracts	7,904	9,689
Other regulatory assets	784,231	815,058
Unrealized gain on derivative instruments	94,621	26,197

Power contract acquisition adjustment gain	46,924	63,660
Operating lease right-of-use asset	193,509	184,957
Other	180,204	163,374
Total other long-term and regulatory assets	1,419,600	1,400,416
Total assets	$ 17,187,514	$ 15,871,884

The accompanying notes are an integral part of the consolidated financial statements.

PUGET ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands)

CAPITALIZATION AND LIABILITIES

	December 31,	
	2022	2021
Capitalization:		
Common shareholder’s equity:		
Common stock $0.01 par value, 1,000 shares authorized, 200 shares outstanding	$ —	$ —
Additional paid-in capital	3,523,532	3,523,532
Retained earnings	1,465,331	1,067,216
Accumulated other comprehensive income (loss), net of tax	(24,774)	(27,432)
Total common shareholder’s equity	4,964,089	4,563,316
Long-term debt:		
First mortgage bonds and senior notes	4,662,000	4,662,000
Pollution control bonds	161,860	161,860
Long-term debt	2,034,300	1,583,300
Debt discount, issuance costs and other	(194,787)	(203,394)
Total long-term debt	6,663,373	6,203,766
Total capitalization	11,627,462	10,767,082
Current liabilities:		
Accounts payable	665,750	444,384
Short-term debt	441,300	140,000
Current maturities of long-term debt	—	450,000
Accrued expenses:		
Taxes	116,098	127,398
Salaries and wages	60,537	47,936
Interest	62,148	67,807
Unrealized loss on derivative instruments	124,976	63,309
Power contract acquisition adjustment loss	1,638	1,785
Operating lease liabilities	20,342	20,398
Other	70,685	62,406
Total current liabilities	1,563,474	1,425,423
Other Long-term and regulatory liabilities:		
Deferred income taxes	985,947	912,484
Unrealized loss on derivative instruments	18,366	40,965
Purchased gas adjustment liability	3,536	—
Regulatory liabilities	1,147,143	844,184
Regulatory liability for deferred income taxes	811,161	865,976
Regulatory liabilities related to power contracts	63,660	80,934
Power contract acquisition adjustment loss	6,266	7,904

Operating lease liabilities	181,265	172,510
Finance lease liabilities	102,518	105,303
Other deferred credits	676,716	649,119
Total long-term and regulatory liabilities	3,996,578	3,679,379
Commitments and contingencies (Note 16)		
Total capitalization and liabilities	$ 17,187,514	$ 15,871,884

The accompanying notes are an integral part of the consolidated financial statements.

PUGET ENERGY, INC.

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY

(Dollars in Thousands)

	Common Stock					
	Shares	Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Equity
Balance at December 31, 2019	200	$ —	$ 3,308,957	$ 775,491	$ (84,149)	$ 4,000,299
Net income (loss)	—	—	—	182,717	—	182,717
Common stock dividend paid	—	—	—	(45,421)	—	(45,421)
Capital contribution	—	—	4,575	—	—	4,575
Other comprehensive income (loss)	—	—	—	—	(2,288)	(2,288)
Balance at December 31, 2020	200	$ —	$ 3,313,532	$ 912,787	$ (86,437)	$ 4,139,882
Net income (loss)	—	—	—	260,849	—	260,849
Common stock dividend paid	—	—	—	(106,420)	—	(106,420)
Capital contribution	—	—	210,000	—	—	210,000
Other comprehensive income (loss)	—	—	—	—	59,005	59,005
Balance at December 31, 2021	200	$ —	$ 3,523,532	$ 1,067,216	$ (27,432)	$ 4,563,316
Net income (loss)	—	—	—	414,345	—	414,345
Common stock dividend paid	—	—	—	(16,230)	—	(16,230)
Other comprehensive income (loss)	—	—	—	—	2,658	2,658
Balance at December 31, 2022	200	$ —	$ 3,523,532	$ 1,465,331	$ (24,774)	$ 4,964,089

The accompanying notes are an integral part of the consolidated financial statements.

PUGET ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)

	Year Ended December 31,		
	2022	2021	2020
Operating Activities:			
Net Income (Loss)	$ 414,345	$ 260,849	$ 182,717
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	663,232	704,783	647,755
Conservation amortization	116,942	103,147	99,585
Deferred income taxes and tax credits, net	17,941	(1,228)	(6,287)
Net unrealized (gain) loss on derivative instruments	(261,177)	(13,785)	26,807
(Gain) or loss on extinguishment of debt	—	—	13,546
AFUDC - equity	(28,310)	(27,806)	(23,223)
Production tax credit	—	(45,562)	(39,761)
Other non-cash	4,757	(9,284)	9,069
Funding of pension liability	(18,000)	(18,000)	(18,000)
Regulatory assets and liabilities	(90,335)	(126,625)	(152,417)
Purchased gas adjustment	37,256	29,720	45,111
Other long term assets and liabilities	(23,639)	(24,761)	(3,171)
Change in certain current assets and liabilities:			
Accounts receivable and unbilled revenue	(258,188)	(96,498)	(32,994)
Materials and supplies	(18,885)	5,046	(2,649)
Fuel and natural gas inventory	(34,682)	(10,598)	3,287
Prepayments and other	4,186	(997)	(18,242)
Accounts payable	237,260	84,775	16,516
Taxes payable	(11,300)	16,646	10,773
Other	18,215	(3,224)	(30,854)
Net cash provided by (used in) operating activities	769,618	826,598	727,568
Investing activities:			
Construction expenditures - excluding equity AFUDC	(1,004,713)	(922,144)	(908,136)
Other	(567)	1,367	5,340
Net cash provided by (used in) investing activities	(1,005,280)	(920,777)	(902,796)
Financing Activities:			
Change in short-term debt, net	301,300	(233,800)	197,800
Dividends paid	(16,230)	(106,420)	(45,421)
Investment from parent	—	210,000	4,575
Proceeds from long-term debt and bonds issued	448,075	961,538	644,690
Redemption of bonds and notes	(450,000)	(502,410)	(450,000)
Repayment of term loan and revolving credit	—	(234,000)	(159,400)
Other	18,152	20,570	(1,311)
Net cash provided by (used in) financing activities	301,297	115,478	190,933
Net increase (decrease) in cash, cash equivalents, and restricted cash	65,635	21,299	15,705
Cash, cash equivalents, and restricted cash at beginning of period	103,150	81,851	66,146
Cash, cash equivalents, and restricted cash at end of period	$ 168,785	$ 103,150	$ 81,851
Supplemental cash flow information:			
Cash payments for interest (net of capitalized interest)	$ 320,656	$ 329,894	$ 336,441
Cash payments (refunds) for income taxes	46,785	22,647	4,974
Non-cash financing and investing activities:			
Accounts payable for capital expenditures eliminated from cash flow	$ 68,357	$ 89,958	$ 58,304
Recognition of finance lease eliminated from cash flows	454	105,176	—

The accompanying notes are an integral part of the consolidated financial statements.

PUGET SOUND ENERGY, INC.

CONSOLIDATED STATEMENTS OF INCOME

(Dollars in Thousands)

	Year Ended December 31,		
	2022	2021	2020
Operating revenue:			
Electric	$ 2,961,457	$ 2,671,623	$ 2,319,416
Natural gas	1,209,636	1,067,418	980,913
Other	45,080	66,620	26,121
Total operating revenue	4,216,173	3,805,661	3,326,450
Operating expenses:			
Energy costs:			
Purchased electricity	1,038,728	784,565	593,719
Electric generation fuel	348,159	282,254	199,107
Residential exchange	(77,715)	(82,225)	(80,294)
Purchased natural gas	500,849	398,553	362,872
Unrealized (gain) loss on derivative instruments, net	(261,177)	(13,785)	26,807
Utility operations and maintenance	665,259	629,864	597,048
Non-utility expense and other	47,194	56,242	42,266
Depreciation and amortization	657,349	704,372	647,546
Conservation amortization	116,942	103,147	99,585
Taxes other than income taxes	388,123	362,527	328,602
Total operating expenses	3,423,711	3,225,514	2,817,258
Operating income (loss)	792,462	580,147	509,192
Other income (deductions):			
Other income	36,684	46,523	46,923
Other expense	(19,569)	(14,467)	(23,207)
Interest charges:			
AFUDC	18,444	16,743	14,827
Interest expense	(256,774)	(248,624)	(247,213)
Income (loss) before income taxes	571,247	380,322	300,522
Income tax (benefit) expense	80,295	44,259	26,242
Net income (loss)	$ 490,952	$ 336,063	$ 274,280

The accompanying notes are an integral part of the consolidated financial statements.

PUGET SOUND ENERGY, INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in Thousands)

	Year Ended December 31,		
	2022	2021	2020
Net income (loss)	$ 490,952	$ 336,063	$ 274,280
Other comprehensive income (loss):			
Net unrealized gain (loss) from pension and postretirement plans, net of tax of $2,580, $17,925 and $1,897, respectively	9,711	67,431	7,136
Amortization of treasury interest rate swaps to earnings, net of tax of $102, $103 and $102, respectively	386	384	385
Other comprehensive income (loss)	10,097	67,815	7,521
Comprehensive income (loss)	$ 501,049	$ 403,878	$ 281,801

The accompanying notes are an integral part of the consolidated financial statements.

PUGET SOUND ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

(Dollars in Thousands)

ASSETS

	December 31, 2022	December 31, 2021
Utility plant (at original cost, including construction work in progress of $861,801 and $870,204, respectively):		
Electric plant	$ 12,071,531	$ 11,535,976
Natural gas plant	5,276,156	5,054,622
Common plant	1,125,217	1,177,598
Less: Accumulated depreciation and amortization	(6,688,033)	(6,416,246)
Net utility plant	11,784,871	11,351,950
Other property and investments:		
Other property and investments	80,076	74,602
Total other property and investments	80,076	74,602
Current assets:		
Cash and cash equivalents	102,840	50,043
Restricted cash	63,045	46,204
Accounts receivable, net of allowance for doubtful accounts of $41,962 and $34,958, respectively	671,071	402,602
Unbilled revenue	284,014	271,606
Materials and supplies, at average cost	132,172	113,287
Fuel and natural gas inventory, at average cost	91,783	58,129
Unrealized gain on derivative instruments	587,029	128,210
Prepaid expenses and other	41,940	46,293
Total current assets	1,973,894	1,116,374
Other long-term and regulatory assets:		
Power cost adjustment mechanism	112,207	79,546
Purchased gas adjustment receivable	—	57,935
Other regulatory assets	784,231	815,058
Unrealized gain on derivative instruments	94,621	26,197
Operating lease right-of-use asset	193,509	184,957
Other	176,833	162,391
Total other long-term and regulatory assets	1,361,401	1,326,084
Total assets	$ 15,200,242	$ 13,869,010

The accompanying notes are an integral part of the consolidated financial statements.

PUGET SOUND ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

(Dollars in Thousands)

CAPITALIZATION AND LIABILITIES

	Year Ended December 31, 2022	Year Ended December 31, 2021
Capitalization:		
Common shareholder’s equity:		
Common stock $0.01 par value, 150,000,000 shares authorized, 85,903,791 shares outstanding	$ 859	$ 859
Additional paid-in capital	3,535,105	3,485,105
Retained earnings	1,438,163	982,607
Accumulated other comprehensive income (loss), net of tax	(103,044)	(113,141)

Total common shareholder’s equity	4,871,083	4,355,430
Long-term debt:		
First mortgage bonds and senior notes	4,662,000	4,662,000
Pollution control bonds	161,860	161,860
Debt discount, issuance costs and other	(37,095)	(39,141)
Total long-term debt	4,786,765	4,784,719
Total capitalization	9,657,848	9,140,149
Current liabilities:		
Accounts payable	664,457	451,716
Short-term debt	357,000	140,000
Accrued expenses:		
Taxes	116,472	133,406
Salaries and wages	60,537	47,936
Interest	52,170	51,832
Unrealized loss on derivative instruments	124,976	63,309
Operating lease liabilities	20,342	20,398
Other	70,685	62,406
Total current liabilities	1,466,639	971,003
Other long-term and regulatory liabilities:		
Deferred income taxes	1,139,600	1,084,203
Unrealized loss on derivative instruments	18,366	40,965
Purchased gas adjustment liability	3,536	—
Regulatory liabilities	1,145,879	842,920
Regulatory liability for deferred income taxes	811,724	866,541
Operating lease liabilities	181,265	172,510
Finance lease liabilities	102,518	105,303
Other deferred credits	672,867	645,416
Total long-term and regulatory liabilities	4,075,755	3,757,858
Commitments and contingencies (Note 16)		
Total capitalization and liabilities	$ 15,200,242	$ 13,869,010

The accompanying notes are an integral part of the consolidated financial statements.

PUGET SOUND ENERGY, INC.

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER’S EQUITY

(Dollars in Thousands)

	Common Stock					
	Shares	Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Equity
Balance at December 31, 2019	85,903,791	$ 859	$ 3,485,105	$ 751,193	$ (188,477)	$ 4,048,680
Net income (loss)	—	—	—	274,280	—	274,280
Common stock dividend paid	—	—	—	(149,072)	—	(149,072)
Other comprehensive income (loss)	—	—	—	—	7,521	7,521
Balance at December 31, 2020	85,903,791	$ 859	$ 3,485,105	$ 876,401	$ (180,956)	$ 4,181,409
Net income (loss)	—	—	—	336,063	—	336,063
Common stock dividend paid	—	—	—	(229,857)	—	(229,857)
Other comprehensive income (loss)	—	—	—	—	67,815	67,815
Balance at December 31, 2021	85,903,791	$ 859	$ 3,485,105	$ 982,607	$ (113,141)	$ 4,355,430
Net income (loss)	—	—	—	490,952	—	490,952
Common stock dividend paid	—	—	—	(35,396)	—	(35,396)
Capital Contribution	—	—	50,000	—	—	50,000
Other comprehensive income (loss)	—	—	—	—	10,097	10,097
Balance at December 31, 2022	85,903,791	$ 859	$ 3,535,105	$ 1,438,163	$ (103,044)	$ 4,871,083

The accompanying notes are an integral part of the consolidated financial statements.

PUGET SOUND ENERGY, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)

	Year Ended December 31,		
	2022	2021	2020
Operating Activities:			
Net Income (Loss)	$ 490,952	$ 336,063	$ 274,280
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	657,349	704,372	647,546
Conservation amortization	116,942	103,147	99,585
Deferred income taxes and tax credits, net	(2,103)	(8,652)	15,271
Net unrealized (gain) loss on derivative instruments	(261,177)	(13,785)	26,807
AFUDC - equity	(28,310)	(27,806)	(23,223)
Production tax credit	—	(45,562)	(39,761)
Other non-cash	(6,005)	(19,761)	(1,575)
Funding of pension liability	(18,000)	(18,000)	(18,000)
Regulatory assets and liabilities	(90,335)	(126,625)	(152,417)
Purchased gas adjustment	37,256	29,720	45,111
Other long term assets and liabilities	(14,359)	(14,097)	8,764
Change in certain current assets and liabilities:			
Accounts receivable and unbilled revenue	(252,308)	(96,487)	(33,835)
Materials and supplies	(18,885)	5,046	(2,649)
Fuel and natural gas inventory	(33,654)	(10,598)	3,287
Prepayments and other	4,186	(997)	(18,242)
Accounts payable	228,635	92,007	16,549
Taxes payable	(16,934)	26,152	7,277
Other	24,211	6,256	(29,965)
Net cash provided by (used in) operating activities	817,461	920,393	824,810
Investing Activities:			
Construction expenditures - excluding equity AFUDC	(1,000,810)	(908,273)	(876,437)
Other	(567)	1,367	5,340
Net cash provided by (used in) investing activities	(1,001,377)	(906,906)	(871,097)
Financing Activities			
Change in short-term debt, net	217,000	(233,800)	197,800
Dividends paid	(35,396)	(229,857)	(149,072)
Investment from parent	50,000	—	—
Proceeds from long-term debt and bonds issued	—	446,063	—
Redemption of bonds and notes	—	(2,410)	—
Other	21,950	22,043	13,389
Net cash provided by (used in) financing activities	253,554	2,039	62,117
Net increase (decrease) in cash, cash equivalents, and restricted cash	69,638	15,526	15,830
Cash, cash equivalents, and restricted cash at beginning of period	96,247	80,721	64,891
Cash, cash equivalents, and restricted cash at end of period	$ 165,885	$ 96,247	$ 80,721
Supplemental cash flow information:			
Cash payments for interest (net of capitalized interest)	$ 233,746	$ 223,484	$ 228,420
Cash payments (refunds) for income taxes	93,058	38,442	11,521
Non-cash financing and investing activities:			
Accounts payable for capital expenditures eliminated from cash flow	$ 68,357	$ 89,958	$ 58,304
Recognition of finance lease eliminated from cash flows	454	105,176	—

The accompanying notes are an integral part of the consolidated financial statements.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Basis of Presentation

Puget Energy is an energy services holding company that owns Puget Sound Energy (PSE). PSE is a public utility incorporated in the state of Washington that furnishes electric and natural gas services in a territory covering approximately 6,000 square miles, primarily in the Puget Sound region. Puget Energy also has a wholly-owned non-regulated subsidiary, Puget LNG, LLC (Puget LNG), which has the sole purpose of owning, developing and financing the non-regulated activity of the Tacoma liquefied natural gas (LNG) facility. PSE and Puget LNG are considered related parties with similar ownership by Puget Energy. Therefore, capital and operating costs that are incurred by PSE and allocated to Puget LNG are related party transactions by nature.

In 2009, Puget Holdings, LLC (Puget Holdings), owned by a consortium of long-term infrastructure investors, completed its merger with Puget Energy (the merger). As a result of the merger, all of Puget Energy's common stock is indirectly owned by Puget Holdings. The acquisition of Puget Energy was accounted for in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 805, "Business Combinations" (ASC 805), as of the date of the merger. ASC 805 requires the acquirer to recognize and measure identifiable assets acquired and liabilities assumed at fair value as of the merger date.

The consolidated financial statements of Puget Energy reflect the accounts of Puget Energy and its subsidiaries. PSE's consolidated financial statements include the accounts of PSE and its subsidiary. Puget Energy and PSE are collectively referred to herein as "the Company". The consolidated financial statements are presented after elimination of all significant intercompany items and transactions. PSE's consolidated financial statements continue to be accounted for on a historical basis and do not include any ASC 805, "Business Combinations" (ASC 805) purchase accounting adjustments. The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

Utility Plant

Puget Energy and PSE capitalize, at original cost, additions to utility plant, including renewals and betterments. Costs include indirect costs such as engineering, supervision, certain taxes, pension and other employee benefits and an allowance for funds used during construction (AFUDC). Replacements of minor items of property are included in maintenance expense. When the utility plant is retired and removed from service, the original cost of the property is charged to accumulated depreciation and costs associated with removal of the property, less salvage, are charged to the cost of removal regulatory liability.

Planned Major Maintenance

Planned major maintenance is an activity that typically occurs when PSE overhauls or substantially upgrades various systems and equipment on a scheduled basis. Costs related to planned major maintenance are deferred and amortized to the next scheduled major maintenance. This accounting method also follows the Washington Utilities and Transportation Commission (Washington Commission) regulatory treatment related to these generating facilities.

Other Property and Investments

For PSE, the costs of other property and investments (i.e., non-utility) are stated at historical cost. Expenditures for refurbishment and improvements that significantly add to productive capacity or extend useful life of an asset are capitalized. Replacements of minor items are expensed on a current basis. Gains and losses on assets sold or retired, which were previously recorded in utility plant, are apportioned between regulatory assets/liabilities and earnings. However, gains and losses on assets sold or retired, not previously recorded in utility plant, are reflected in earnings.

Depreciation and Amortization

The Company provides for depreciation and amortization on a straight-line basis. Amortization is recorded for intangibles such as regulatory assets and liabilities, computer software and franchises. The annual depreciation provision stated as a percent of a depreciable electric utility plant was 3.4%, 3.4%, and 3.5% in 2022, 2021, and 2020, respectively; depreciable natural gas utility plant was 2.9%, 2.8%, and 2.9% in 2022, 2021, and 2020, respectively; and depreciable common utility plant

was 7.1%, 6.8% and 7.3% in 2022, 2021, and 2020, respectively. The cost of removal is collected from PSE's customers through depreciation expense and any excess is recorded as a regulatory liability.

Tacoma LNG Facility

In February 2022, the Tacoma LNG facility at the Port of Tacoma completed commissioning and commenced commercial operations. In December 2019, the Puget Sound Clean Air Agency (PSCAA) issued the air quality permit for the facility, and the Pollution Hearings Control Board of Washington State upheld the approval following extended litigation. The Tacoma LNG facility provides peak-shaving services to PSE's natural gas customers, and provides LNG as fuel to transportation customers, particularly in the marine market at a lower cost due to the facility's scale.

Pursuant to an order by the Washington Commission, PSE will be allocated approximately 43.0% of common capital and operating costs, consistent with the regulated portion of the Tacoma LNG facility. The remaining 57.0% of common capital and operating costs of the Tacoma LNG facility will be allocated to Puget LNG. Per this allocation of costs, $249.1 million of non-utility plant and $244.7 million of construction work in progress related to Puget LNG's portion of the Tacoma LNG facility is reported in the Puget Energy "Other property and investments" financial statement line item as of December 31, 2022, and December 31, 2021, respectively. Additionally, $11.6 million, $1.3 million, and $0.6 million of operating costs are reported in the Puget Energy "Non-utility expense and other" financial statement line item in 2022, 2021, and 2020, respectively. Additionally, $245.7 million and $239.6 million of plant in service and construction work in progress related to PSE's portion of the Tacoma LNG facility is reported in the PSE "Utility plant - Natural gas plant" financial statement line item as of December 31, 2022, and December 31, 2021, respectively, as PSE is a regulated entity.

Cash and Cash Equivalents

Cash and cash equivalents consist of demand bank deposits and short-term highly liquid investments with original maturities of three months or less at the time of purchase. The carrying amounts of cash and cash equivalents are reported at cost and approximate fair value, due to the short-term maturity.

Restricted Cash

Restricted cash amounts primarily represent cash posted as collateral for derivative contracts as well as funds required to be set aside for contractual obligations related to transmission and generation facilities.

Materials and Supplies

Materials and supplies are used primarily in the operation and maintenance of electric and natural gas distribution and transmission systems as well as spare parts for combustion turbines used for the generation of electricity. The Company records these items at weighted-average cost.

Fuel and Natural Gas Inventory

Fuel and natural gas inventory is used in the generation of electricity and for future sales to the Company's natural gas customers. Fuel inventory consists of coal, diesel and natural gas used for generation. Natural gas inventory consists of natural gas and LNG held in storage for future sales. The Company records fuel inventory and natural gas inventory for unregulated operations at the lower of cost or net realizable value and natural gas inventory for regulated operations at average cost.

Regulatory Assets and Liabilities

PSE accounts for its regulated operations in accordance with ASC 980, "Regulated Operations" (ASC 980). ASC 980 requires PSE to defer certain costs or losses that would otherwise be charged to expense, if it is probable that future rates will permit recovery of such costs. It similarly requires deferral of revenues or gains that are expected to be returned to customers in the future. Accounting under ASC 980 is appropriate as long as rates are established by or subject to approval by independent third-party regulators; rates are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers. In most cases, PSE classifies regulatory assets and liabilities as long-term when amortization periods extend longer than one year. For further details regarding regulatory assets and liabilities, see Note 4, "Regulation and Rates" to the consolidated financial statements included in Item 8 of this report.

Puget Energy recorded regulatory assets and liabilities at the time of the merger related to power purchase contracts.

Allowance for Funds Used During Construction

AFUDC represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. The amount of AFUDC recorded in each accounting period varies depending primarily upon the level of construction work in progress and the AFUDC rate used. AFUDC is capitalized as a part of the cost of utility plant; the AFUDC debt portion is credited to interest expense, while the AFUDC equity portion is credited to other income. Cash inflow related to AFUDC does not occur until these charges are reflected in rates. The AFUDC rate authorized by the Washington Commission for natural gas and electric utility plant additions effective December 19, 2017, was 7.60%. Effective October 1, 2020 for natural gas and October 15, 2020 for electric the authorized AFUDC rate is 7.39%.

The Washington Commission authorized the Company to calculate AFUDC using its allowed rate of return. To the extent amounts calculated using this rate exceed the AFUDC calculated rate using the Federal Energy Regulatory Commission (FERC) formula, PSE capitalizes the excess as a deferred asset, crediting other income. The deferred asset is being amortized over the average useful life of PSE's non-project electric utility plant which is approximately 30 years.

Revenue Recognition

Operating utility revenue is recognized when the basis of services is rendered, which includes estimated unbilled revenue. Revenue from retail sales is billed based on tariff rates approved by the Washington Commission. PSE's estimate of unbilled revenue is based on a calculation using meter readings from its automated meter reading system. The estimate calculates unbilled usage at the end of each month as the difference between the customer meter readings on the last day of the month and the last customer meter readings billed. The unbilled usage is then priced at published rates for each tariff rate schedule to estimate the unbilled revenues by customer.

PSE collected Washington State excise taxes (which are a component of general retail customer rates) and municipal taxes totaling $292.8 million, $268.5 million and $240.8 million for 2022, 2021, and 2020, respectively. The Company reports the collection of such taxes on a gross basis in operation revenue and as expense in taxes other than income taxes in the accompanying consolidated statements of income.

PSE's electric and natural gas operations contain a revenue decoupling mechanism under which PSE's actual energy delivery revenues related to electric transmission and distribution, natural gas operations and general administrative costs are compared with authorized revenues allowed under the mechanism. The mechanism mitigates volatility in revenue and gross margin erosion due to weather and energy efficiency. Any differences in revenue are deferred to a regulatory asset for under recovery or regulatory liability for over recovery under alternative revenue recognition standard. Revenue is recognized under this program when deemed collectible within 24 months based on alternative revenue recognition guidance. Decoupled rate increases are effective May 1 of each year subject to a soft rate cap of total revenue for decoupled rate schedules, where rate cap is applied to under-collected revenue and any over-collected revenues are passed back to customers at 100%. Any excess under-recovered revenue above the rate cap will be included in the following year's decoupled rate and the Company will only be able to recognize revenue below the rate cap of total revenue for decoupled rate schedules. For revenue deferrals exceeding the annual rate cap of total revenue for decoupled rate schedules, the Company will assess the excess amount to determine its ability to be collected within 24 months per GAAP rules. The soft rate cap test, which limits the amount of revenues PSE can collect in its annual filings, is 5.0% for natural gas customers and 3.0% for electric customers. The Company will not record any decoupling revenue that is expected to take longer than 24 months to collect following the end of the annual period in which the revenues would have otherwise been recognized. Once determined to be collectible within 24 months, any previously non-recognized amounts will be recognized. Revenues associated with energy costs under the power cost adjustment (PCA) mechanism and purchased gas adjustment (PGA) mechanism are excluded from the decoupling mechanism.

Allowance for Credit Losses

The Company measures expected credit losses on trade receivables on a collective basis by receivable type, which include electric retail receivables, gas retail receivables, and electric wholesale receivables. The estimate of expected credit losses considers historical credit loss information that is adjusted for current conditions and reasonable and supportable forecasts.

The following table presents the activity in the allowance for credit losses for accounts receivable at December 31, 2022, and 2021:

Puget Energy and
Puget Sound Energy

(Dollars in Thousands)	Year Ended December 31,	
Allowance for credit losses:	2022	2021
Beginning balance	$ 34,958	20,080
Provision for credit loss expense[1]	28,316	27,204
Receivables charged-off	(21,312)	(12,326)
Total ending allowance balance	$ 41,962	$ 34,958

[1] *$7.1 million and $2.8 million of provision were deferred as cost specific to COVID-19 in 2022 and 2021, respectively.*

Self-Insurance

PSE is self-insured for storm damage and certain environmental contamination associated with current operations occurring on PSE-owned property. In addition, PSE is required to meet a deductible for a portion of the risk associated with comprehensive liability, workers' compensation claims and catastrophic property losses other than those which are storm related. The cumulative annual cost threshold for deferral of storms under the mechanism is $10.0 million. Additionally, costs may only be deferred if the outage meets the Institute of Electrical and Electronics Engineers outage criteria for system average interruption duration index and qualifying costs exceed $0.5 million per qualified storm.

Federal Income Taxes

For presentation in Puget Energy's and PSE's separate financial statements, income taxes are allocated to the subsidiaries on the basis of separate company computations of tax, modified by allocating certain consolidated group limitations which are attributed to the separate company. Taxes payable or receivable are settled with Puget Holdings, which is the ultimate taxpayer.

Natural Gas Off-System Sales and Capacity Release

PSE contracts for firm natural gas supplies and holds firm transportation and storage capacity sufficient to meet the expected peak winter demand for natural gas by its firm customers. Due to the variability in weather, winter peaking consumption of natural gas by most of its customers and other factors, PSE holds contractual rights to natural gas supplies and transportation and storage capacity in excess of its average annual requirements to serve firm customers on its distribution system. For much of the year, there is excess capacity available for third-party natural gas sales, exchanges and capacity releases. PSE sells excess natural gas supplies, enters into natural gas supply exchanges with third parties outside of its distribution area and releases to third parties excess interstate natural gas pipeline capacity and natural gas storage rights on a short-term basis to mitigate the costs of firm transportation and storage capacity for its core natural gas customers. The proceeds from such activities, net of transactional costs, are accounted for as reductions in the cost of purchased natural gas and passed on to customers through the PGA mechanism, with no direct impact on net income. As a result, PSE nets the sales revenue and associated cost of sales for these transactions in purchased natural gas.

As part of the Company's electric operations, PSE purchases natural gas for its gas-fired generation facilities. The projected volume of natural gas for power is relative to the price of natural gas. Based on the market prices for natural gas, PSE may use the natural gas it has already purchased to generate power or PSE may sell the already purchased natural gas. The net proceeds from selling natural gas, previously purchased for power generation, are accounted for in electric operating revenue and are included in the PCA mechanism.

Production Tax Credit

Production Tax Credits (PTCs) represent federal income tax incentives available to taxpayers that generate energy from qualifying renewable sources during the first ten years of operation. Before the 2017 GRC, the tax savings from these credits were intended to be refunded by PSE to its customers when monetized, used on the income tax return, through its revenue requirement as initially approved by the Washington Commission. As the Company had not generated taxable income with which to monetize the credits, they had not been refunded to customers. Amounts to be refunded have been recorded as a regulatory liability with an offsetting reduction to revenue as it was intended to be refunded through the revenue requirement. A deferred tax asset and reduction to deferred tax expense were also recorded for the regulatory liability. These entries resulted

in no net income impact. In connection with the GRC settlement in 2017, the Washington Commission authorized the Company to utilize the tax savings associated with the monetization of the PTCs to fund the following: (i) Colstrip Community Transition Fund, (ii) unrecovered Colstrip plant and (iii) incurred decommissioning and remediation costs for Colstrip. As PTCs will no longer be refunded to customers through the revenue requirement, a non-cash increase to revenue and deferred tax expense will be recorded as the PTCs are monetized. These entries will result in no net income impact. For the tax year ending December 31, 2022, there was no PTC monetized as there were no PTC carryforwards from 2021. For the tax years ending December 31, 2021 and 2020, $45.6 million and $39.8 million of PTCs were monetized through tax filings.

Accounting for Derivatives

ASC 815, "Derivatives and Hedging" (ASC 815) requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value unless the contracts qualify for an exception. PSE enters into derivative contracts to manage its energy resource portfolio and interest rate exposure including forward physical and financial contracts and swaps. Some of PSE’s physical electric supply contracts qualify for the normal purchase normal sale (NPNS) exception to derivative accounting rules. PSE may enter into financial fixed price contracts to economically hedge the variability of certain index-based contracts. Those contracts that do not meet the NPNS exception are marked-to-market to current earnings in the statements of income, subject to deferral under ASC 980, for natural gas related derivatives due to the PGA mechanism. For additional information, see Note 10, "Accounting for Derivative Instruments and Hedging Activities" to the consolidated financial statements included in Item 8 of this report.

Fair Value Measurements of Derivatives

ASC 820, “Fair Value Measurements and Disclosures” (ASC 820), defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). As permitted under ASC 820, the Company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing the majority of its assets and liabilities measured and reported at fair value. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company primarily applies the market approach for recurring fair value measurements as it believes that the approach is used by market participants for these types of assets and liabilities. Accordingly, the Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

The Company values derivative instruments based on daily quoted prices from an independent external pricing service. When external quoted market prices are not available for derivative contracts, the Company uses a valuation model that uses volatility assumptions relating to future energy prices based on specific energy markets and utilizes externally available forward market price curves. All derivative instruments are sensitive to market price fluctuations that can occur on a daily basis. For additional information, see Note 11, "Fair Value Measurements" to the consolidated financial statements included in Item 8 of this report.

Debt-Related Costs

Debt premiums, discounts, expenses and amounts received or incurred to settle hedges are amortized over the life of the related debt for the Company. The premiums and costs associated with reacquired debt are deferred and amortized over the life of the related new issuance, in accordance with ratemaking treatment for PSE and presented net of long-term liabilities on the balance sheet.

Leases

PSE determines if an arrangement is, or contains, a lease at inception of the contract. If the arrangement is, or contains a lease, PSE assesses whether the lease is operating or financing for income statement and balance sheet classification. Operating leases are included in operating lease right-of-use (ROU) assets, operating lease current liabilities, and operating lease liabilities in our consolidated balance sheets. Finance leases are included in utility plant, other current liabilities, and finance lease liabilities in our consolidated balance sheets.

ROU assets represent the right to use an underlying asset for the lease term, and consist of the amount of the initial measurement of the lease liability, any lease payments made to the lessor at or before the commencement date, minus any lease incentives received, and any initial direct costs incurred by the lessee. Lease liabilities represent our obligation to make lease payments arising from the lease and are measured at present value of the lease payments not yet paid, discounted using the discount rate for the lease, determined based on PSE's incremental borrowing rate, at commencement. As most of PSE's leases do not provide an implicit interest rate, PSE uses the incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. For fleet, IT and wind farm leases, this rate is applied using a portfolio approach. The lease terms may include options to extend or terminate the lease when it is reasonably certain that PSE will exercise that option. On the statement of income, operating leases are generally accounted for under a straight-line expense model, while finance leases, which were previously referred to as capital leases, are generally accounted for under a financing model. Consistent with the previous lease guidance, however, the standard allows rate-regulated utilities to recognize expense consistent with the timing of recovery in rates.

PSE has lease agreements with lease and non-lease components. Non-lease components comprise common area maintenance and utilities, and are accounted for separately from lease components.

Variable Interest Entities

On April 12, 2017, PSE entered into a Power Purchase Agreement (PPA) with Skookumchuck Wind Energy Project, LLC (Skookumchuck) in which Skookumchuck would develop a wind generation facility and, once completed, sell bundled energy and associated attributes, namely renewable energy credits to PSE over a term of 20 years. Skookumchuck commenced commercial operation in November 2020. PSE has no equity investment in Skookumchuck but is Skookumchuck's only customer. Based on the terms of the contract, PSE will receive all of the output of the facility, subject to curtailment rights. PSE has concluded that it is not the primary beneficiary of this VIE since it does not control the commercial and operating activities of the facility. Additionally, PSE does not have the obligation to absorb losses or receive benefits. Therefore, PSE will not consolidate the VIE. Purchased energy of $14.6 million was recognized in purchased electricity on the Company's consolidated statements of income for the year ended December 31, 2022 and $1.4 million is included in accounts payable on the Company's consolidated balance sheet for the year ended December 31, 2022. Purchased energy of $19.0 million was recognized in purchased electricity on the Company's consolidated statements of income and $2.7 million included in accounts payable on the Company's consolidated balance sheet for the year ended December 31, 2021.

On May 28, 2020, PSE entered into a PPA with Golden Hills Wind Farm, LLC (Golden Hills) pursuant to which Golden Hills would develop a wind generation facility and, once completed, sell bundled energy and associated attributes, namely RECs to PSE over a term of 20 years. On April 29, 2022, Golden Hills commenced commercial operations. PSE has no equity investment in Golden Hills but is Golden Hills's only customer. Based on the terms of the contract, PSE will receive all of the output of the facility, subject to curtailment rights. PSE has concluded that Golden Hills is a VIE and that PSE is not the primary beneficiary of this VIE since it does not control the commercial and operating activities of the facility. Additionally, PSE does not have the obligation to absorb losses or receive benefits. Therefore, PSE will not consolidate the VIE. Purchased energy of $18.3 million was recognized in purchased electricity on the Company's consolidated statements of income for the year ended December 31, 2022. There was no balance in accounts payable on the Company's balance sheet as of December 31, 2022.

On February 3, 2021, PSE entered into a PPA with Clearwater Wind Project, LLC (Clearwater) in which Clearwater will develop a wind generation facility on a site located in Rosebud, Custer and Garfield counties, Montana; and, once completed, sell energy and associated attributes to PSE over a term of 25 years. On November 8th, 2022, Clearwater commenced commercial operations. PSE has no equity investment in Clearwater but is Clearwater's only customer. Based on the terms of the contract, PSE will receive all of the output of the facility, subject to curtailment rights. PSE has concluded that Clearwater is a VIE and that PSE is not the primary beneficiary of this VIE since it does not control the commercial and operating activities of the facility. Additionally, PSE does not have the obligation to absorb losses or receive benefits. Therefore, PSE will not consolidate the VIE. Purchased energy of $5.7 million was recognized in purchased electricity on the Company's consolidated statements of income for the year ended December 31, 2022. Additionally, $2.5 million was included in accounts payable on the Company's balance sheet as of December 31, 2022.

(2) New Accounting Pronouncements

Recently Adopted Accounting Guidance

Reference Rate Reform

In March 2020, the FASB issued ASU 2020-04, *"Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting*". ASU 2020-04 provides temporary optional expedients and exceptions to the current guidance on contract modifications to ease the financial reporting burdens related to the expected market transition from London Interbank Offered Rate (LIBOR) and other interbank offered rates to alternative reference rates. In December 2022, the FASB issued ASU 2022-06, *"Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848"*. ASU 2022-06 postpones the sunset date of Topic 848 from December 31, 2022 to December 31, 2024. The Company has promissory notes that reference LIBOR. As of December 31, 2022, the Company has not utilized any of the expedients

discussed within this ASU; however, it continues to assess other agreements to determine if LIBOR is included and if the expedients would be utilized through the allowed period of December 2024.

Retirement Benefits

In 2018, the FASB issued ASU 2018-14, "*Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20): Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans"*. This update modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans through added, removed and clarified requirements of relevant disclosures.

The amendments in this update are effective for fiscal years ending after December 15, 2020, for public business entities and for fiscal years ending after December 15, 2021, for all other entities. Early adoption is permitted for all entities. The Company adopted this standard for the year ended December 31, 2020. Refer to Note 13, "Retirement Benefits" to the consolidated financial statements.

Fair Value Measurement

In 2018, the FASB issued ASU 2018-13, *"Fair Value Measurement (Topic 820): Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement"*. The amendments in this update modify the disclosure requirements on fair value measurements in Topic 820, Fair Value Measurement, based on the concepts in the Concepts Statement, including the consideration of costs and benefits. The amendments are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. The Company adopted this update as of January 1, 2020, and it impacted Note 11, "Fair Value Measurements". As the amendment contemplates changes in disclosures only, it did not have a material impact on the Company's results of operations, cash flows, or consolidated balance sheets.

(3) Revenue

The following tables present disaggregated revenue from contracts with customers, and other revenue by major source for the years ended December 31, 2022, December 31, 2021, and December 31, 2020:

Puget Energy and
Puget Sound Energy

(Dollars in Thousands)	Year Ended December 31, 2022			
Revenue from contracts with customers:	Electric	Natural Gas	Other[1]	Total
Retail				
Residential	$ 1,381,858	$ 808,376	$ —	$ 2,190,234
Commercial	981,170	352,243	—	1,333,413
Industrial	116,712	25,096	—	141,808
Other	18,759	—	—	18,759
Wholesale	319,380	—	—	319,380
Transmission and transportation	47,027	20,332	—	67,359
Miscellaneous	13,065	718	50,069	63,852
Total revenue from contracts with customers	$ 2,877,971	$ 1,206,765	$ 50,069	$ 4,134,805
Total other revenue[2]	83,486	2,871	—	86,357
Total operating revenue	$ 2,961,457	$ 1,209,636	$ 50,069	$ 4,221,162

[1] Other includes $5.0 million of Puget LNG revenues recorded at Puget Energy.
[2] Total other revenue includes revenues from derivatives and alternative revenue programs that are not considered revenues from contracts with customers.

Puget Energy and
Puget Sound Energy

(Dollars in Thousands)	Year Ended December 31, 2021			
Revenue from contracts with customers:	Electric	Natural Gas	Other	Total
Retail				
Residential	$ 1,318,326	$ 722,003	$ —	$ 2,040,329
Commercial	902,928	292,275	—	1,195,203
Industrial	108,267	21,741	—	130,008
Other	18,834	392	—	19,226
Wholesale	161,152	—	—	161,152
Transmission and transportation	43,753	20,030	—	63,783
Miscellaneous	47,948	9,863	66,620	124,431
Total revenue from contracts with customers	$ 2,601,208	$ 1,066,304	$ 66,620	$ 3,734,132
Total other revenue[1]	70,415	1,114	—	71,529
Total operating revenue	$ 2,671,623	$ 1,067,418	$ 66,620	$ 3,805,661

[1] Total other revenue includes revenues from derivatives, PTC deferral revenue and alternative revenue programs that are not considered revenues from contracts with customers.

Puget Energy and
Puget Sound Energy

(Dollars in Thousands)	Year Ended December 31, 2020			
Revenue from contracts with customers:	Electric	Natural Gas	Other	Total
Retail				
Residential	$ 1,186,012	$ 662,503	$ —	$ 1,848,515
Commercial	791,898	251,740	—	1,043,638
Industrial	101,567	18,592	—	120,159
Other	26,644	5,227	—	31,871
Wholesale	66,345	—	—	66,345
Transmission and transportation	38,073	19,555	—	57,628
Miscellaneous	25,007	3,107	26,121	54,235
Total revenue from contracts with customers	$ 2,235,546	$ 960,724	$ 26,121	$ 3,222,391
Total other revenue[1]	83,870	20,189	—	104,059
Total operating revenue	$ 2,319,416	$ 980,913	$ 26,121	$ 3,326,450

[1] *Total other revenue includes revenues from derivatives, PTC deferral revenue and alternative revenue programs that are not considered revenues from contracts with customers.*

Revenue at PSE is recognized when performance obligations under the terms of a contract or tariff with our customers are satisfied. Performance obligations are satisfied generally through performance of PSE's obligation over time or with transfer of control of electric power, natural gas, and other revenue from contracts with customers. Revenue is measured as the amount of consideration expected to be received in exchange for transferring goods and services.

Electric and Natural Gas Retail Revenue

Electric and natural gas retail revenue consists of tariff-based sales of electricity and natural gas to PSE's customers. For tariff contracts, PSE has elected the portfolio approach practical expedient model to apply the revenue from contracts with customers to groups of contracts. The Company determined that the portfolio approach will not differ from considering each

contract or performance obligation separately. Electric and natural gas tariff contracts include the performance obligation of standing ready to perform electric and natural gas services. The electricity and natural gas the customer chooses to consume is considered an option and is recognized over time using the output method when the customer simultaneously consumes the electricity or natural gas. PSE has elected the right to invoice practical expedient for unbilled retail revenue. The obligation of standing ready to perform electric service and the consumption of electricity and natural gas at market value implies a right to consideration for performance completed to date. The Company believes that tariff prices approved by the Washington Commission represent stand-alone selling prices for the performance obligations under ASC 606. PSE collects Washington State excise taxes (which are a component of general retail customer rates) and municipal taxes and presents the taxes on a gross basis, as PSE is the taxpayer for those excise and municipal taxes.

Other Revenue from Contracts with Customers

Other revenue from contracts with customers is primarily comprised of electric transmission, natural gas transportation, biogas, and wholesale revenue sold on an intra-month basis.

Electric Transmission and Natural Gas Transportation

Transmission and transportation tariff contracts include the performance obligation to transmit and transport electricity or natural gas. Transfer of control and recognition of revenue occurs over time as the customer simultaneously receives the transmission and transportation services. Measurement of satisfaction of this performance obligation is determined using the output method. Similar to retail revenue, the Company utilizes the right to invoice practical expedient as PSE’s right to consideration is tied directly to the value of power and natural gas transmitted and transported each month. The price is based on the tariff rates that were approved by the Washington Commission or the FERC and, therefore, corresponds directly to the value to the customer for performance completed to date.

Biogas

Biogas is a renewable natural gas fuel that PSE purchases and sells along with the renewable green attributes derived from the renewable natural gas. Biogas contracts include the performance obligations of biogas and renewable credit delivery upon PSE receiving produced biogas from its supplier. Transfer of control and recognition of revenue occurs at a point in time as biogas is considered a storable commodity and may not be consumed as it is delivered.

Wholesale

Wholesale revenue at PSE includes sales of electric power and non-core natural gas to other utilities or marketers. Wholesale revenue contracts include the performance obligation of physical electric power or natural gas. There are typically no added fixed or variable amounts on top of the established rate for power or natural gas and contracts always have a stated, fixed quantity of power or natural gas delivered. Transfer of control and recognition of revenue occurs at a point in time when the customer takes physical possession of electric power or natural gas. Non-core gas consists of natural gas supply in excess of natural gas used for generation, sold to third parties to mitigate the costs of firm transportation and storage capacity for its core natural gas customers. PSE reports non-core gas sold net of costs as PSE does not take control of the natural gas but is merely an agent within the market that connects a seller to a purchaser.

PWI Land Sale

On August 13, 2021, Puget Western, Inc. (PWI) a wholly-owned subsidiary of PSE sold a parcel of land that resulted in $23.2 million of other revenue from contracts with customers. PWI purchases, develops, and sells land holdings throughout PSE's service territory; thus, the sale was reported as non-utility revenue of $23.2 million and non-utility expense of $12.9 million.

Other Revenue

In accordance with ASC 606, PSE separately presents revenue not collected from contracts with customers that falls under other accounting guidance.

Transaction Price Allocated to Remaining Performance Obligations

In December 2020, PLNG entered into a contract with one customer where PLNG is selling LNG over a 10-year delivery period beginning no later than 2024. The contract requires the customer to purchase a minimum annual quantity even if the customer does not take delivery. The price of the LNG includes a fixed charge, a fuel charge that includes both a market index

and fixed margin component and other variable consideration. The fixed transaction price is allocated to the remaining performance obligations which is determined by the fixed charge components multiplied by the outstanding minimum annual quantity. Based on management's best estimate of commencement, the Company expects to recognize this revenue over the following time periods:

Puget Energy *(Dollars in Thousands)*	2024	2025	2026	2027	2028	Thereafter	Total
Remaining Performance Obligations	$ 15,359	19,710	19,454	19,454	19,454	102,135	$ 195,566

The Company has elected the optional exemption in ASC 606, under which the Company does not disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. The primary sources of variability are (a) fluctuating market index prices of natural gas used to determine aspects of variable pricing and (b) variation in volumes that may be delivered to the customer. Both sources of variability are expected to be resolved at or shortly before delivery of each unit of LNG or natural gas. As each unit of LNG or natural gas represents a separate performance obligation, future volumes are wholly unsatisfied.

(4) Regulation and Rates

Regulatory Assets and Liabilities

Regulatory accounting allows PSE to defer certain costs that would otherwise be charged to expense, if it is probable that future rates will permit recovery of such costs. It similarly requires deferral of revenues or gains that are expected to be returned to customers in the future.

The net regulatory assets and liabilities at December 31, 2022, and 2021, are included the following tables:

Puget Sound Energy (Dollars in Thousands)	Remaining Amortization Period	December 31, 2022	December 31, 2021
Environmental remediation	(a)	$ 141,893	$ 127,977
Storm damage costs electric	3 to 5 years	127,524	127,789
PCA mechanism	N/A	112,207	79,546
Chelan PUD contract initiation	8.8 years	62,611	69,699
Deferred Washington Commission AFUDC	30 years	61,463	62,244
Baker Dam licensing operating and maintenance costs	(b)	55,049	54,525
Get to zero depreciation expense deferral (c)	1 to 4 years	49,605	50,220
Lower Snake River	14.4 years	48,536	53,757

Decoupling deferrals and interest (d)	Less than 2 years	36,773	79,125
Unamortized loss on reacquired debt	1 to 45 years	33,732	35,805
Advanced metering infrastructure	3 years	30,431	23,037
Washington Commission LNG	N/A	25,188	1,764
PGA receivable	2 years	—	57,935
Generation plant major maintenance, excluding Colstrip	3 to 7 years	20,374	12,094
Low Income Program Costs	N/A	17,370	21,755
Property tax tracker	Less than 2 years	12,398	25,896
Energy conservation costs	(a)	10,296	3,573
Washington Commission electric vehicle (c)	4 years	7,796	6,109
Regulatory filing fee deferral	N/A	7,559	—
Snoqualmie licensing operating and maintenance costs	(b)	7,445	7,446
Washington Commission COVID-19	N/A	7,051	3,657
Water heater rental property loss	N/A	5,725	5,725
Mint Farm ownership and operating costs	2.3 years	4,317	6,318
Colstrip major maintenance (c)	3 years	4,035	4,035
Various other regulatory assets	(a)	7,060	32,508
Total PSE regulatory assets		$ 896,438	$ 952,539
Deferred income taxes (e)	N/A	(811,724)	(866,541)
Cost of removal	(f)	(639,320)	(563,129)
PGA unrealized gain	N/A	(287,725)	(60,728)
Repurposed production tax credits	N/A	(133,855)	(134,270)
Decoupling liability	Less than 2 years	(63,206)	(36,506)
Green direct	N/A	(11,837)	(13,194)
Refund on counterparty settlement	1 year	(4,353)	—
PGA liability	2 years	(3,536)	—
Various other regulatory liabilities	(a)	(5,583)	(35,093)
Total PSE regulatory liabilities		(1,961,139)	(1,709,461)
PSE net regulatory assets (liabilities)		$ (1,064,701)	$ (756,922)

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(a) *Amortization periods vary depending on timing of underlying transactions.*

(b) *The FERC license requires PSE to incur various O&M expenses over the life of the 40 year and 50 year license for Snoqualmie and Baker, respectively. The regulatory asset represents the net present value of future expenditures and will be offset by actual costs incurred.*

(c) *Amortization period approved in 2022 GRC, beginning January 2023.*

(d) *Decoupling deferrals and interest includes a 24 month GAAP reserve of* zero *and $3.0 million for December 31, 2022 and 2021, respectively.*

(e) *For additional information, see Note 14,"Income Taxes" to the consolidated financial statements included in Item 8 of this report.*

(f) *The balance is dependent upon the cost of removal of underlying assets and the life of utility plant.*

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Puget Energy	Remaining Amortization Period	December 31,	
(Dollars in Thousands)		2022	2021
Total PSE regulatory assets	(a)	$ 896,438	$ 952,539
Puget Energy acquisition adjustments:			
Regulatory assets related to power contracts	3 to 30 years	7,904	9,689
Total Puget Energy regulatory assets		904,342	962,228
Total PSE regulatory liabilities	(a)	(1,961,139)	(1,709,461)
Puget Energy acquisition adjustments:			
Deferred income taxes		563	565
Regulatory liabilities related to power contracts	3 to 30 years	(63,660)	(80,934)
Various other regulatory liabilities	Varies	(1,264)	(1,264)
Total Puget Energy regulatory liabilities		(2,025,500)	(1,791,094)
Puget Energy net regulatory asset (liabilities)		$ (1,121,158)	$ (828,866)

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(a) *Puget Energy's regulatory assets and liabilities include purchase accounting adjustments under ASC 805.*

If the Company determines that it no longer meets the criteria for continued application of ASC 980, the Company would be required to write-off its regulatory assets and liabilities related to those operations not meeting ASC 980 requirements. Discontinuation of ASC 980 could have a material impact on the Company's financial statements.

In accordance with guidance provided by ASC 410, "Asset Retirement and Environmental Obligations (ARO)," PSE reclassified from accumulated depreciation to a regulatory liability $639.3 million and $563.1 million in 2022 and 2021, respectively, for the cost of removal of utility plant. These amounts are collected from PSE's customers through depreciation rates.

General Rate Case Filing

PSE filed a general rate case (GRC) which includes a three-year multiyear rate plan with the Washington Commission on January 31, 2022, requesting an overall increase in electric and natural gas rates of 13.6% and 13.0% respectively in 2023; 2.5% and 2.3%, respectively in 2024; and 1.2% and 1.8%, respectively, in 2025. PSE requested a return on equity of 9.9% in all three rate years. PSE requested an overall rate of return of 7.39% in 2023; 7.44% in 2024; and 7.49% in 2025. The filing requests recovery of forecasted plant additions through 2022 as required by Revised Code of Washington (RCW) 80.28.425 as well as forecasted plant additions through 2025, the final year of the multiyear rate plan.

On January 6, 2023, the Washington Commission approved PSE's natural gas rates in its compliance filing with an overall increase of $70.8 million or 6.4% in 2023 and $19.5 million or 1.65% in 2024, with an effective date of January 7, 2023. On January 10, 2023, the Washington Commission approved PSE's electric rates in its compliance filing with an overall increase of $247.0 million or 10.75% in 2023 and $33.1 million or 1.33% in 2024 with an effective date of January 11, 2023.

PSE filed a GRC with the Washington Commission on June 20, 2019, requesting an overall increase in electric and natural gas rates of 6.9% and 7.9% respectively. On July 8, 2020, the Washington Commission issued its order on PSE's 2019 GRC. The ruling provided for a weighted cost of capital of 7.39% or 6.8% after-tax, and a capital structure of 48.5% in common equity with a return on equity of 9.4%. The order also resulted in a combined net increase to electric of $29.5 million, or 1.6%, and to natural gas of $36.5 million, or 4.0%. However, the Washington Commission extended the amortization of certain regulatory assets, PSE's electric decoupling deferral, and PSE's PGA deferral to mitigate the impact of the rate increase in response to the economic uncertainty created by the COVID-19 pandemic. This reduced the electric revenue increase to approximately $0.9 million, or 0.1% and the natural gas increase to $1.3 million, or 0.2% and became effective October 15, 2020 and October 1, 2020, respectively.

In July 2021, PSE received a Private Letter Ruling (PLR) from the IRS which concluded that in the 2019 GRC the Washington Commission's methodology for reversing plant-related excess deferred income taxes was an impermissible methodology under the IRS normalization and consistency rules. The PLR required adjustments to PSE's rates to bring PSE back into compliance with IRS rules. In September 2021, the Washington Commission amended its order in accordance with the PLR. The annualized overall rate impact was an increase of $15.8 million, or 0.7%, for electric and $3.1 million, or 0.3%, for natural gas for a total of $18.9 million with rates effective October 1, 2021. This led to a combined annualized net increase to electric rates of $77.1 million, or 3.7%, an increase of $17.5 million above the $59.6 million granted in the revised final order. The order also led to a combined annualized net increase to natural gas rates of $45.3 million, or 5.9%, an increase of $2.4 million above the $42.9 million granted in the revised final order. The Washington Commission maintained adjustments that mitigated the impacts of the rate increases in response to the economic instability created by the COVID-19 pandemic, which reduced the electric revenue increase to approximately $48.3 million, or 2.3%, and the natural gas increase to $4.9 million, or 0.6%.

Power Cost Only Rate Case

On December 9, 2020, PSE filed its 2020 power cost only rate case (PCORC). The filing proposed an increase of $78.5 million (or an average of approximately 3.7%) in the Company's overall power supply costs with an anticipated effective date in June 2021. On February 2, 2021, PSE supplemented the PCORC to update its power costs, leading to a requested increase from $78.5 million to $88.0 million (or an average of approximately 4.1%).

On March 2, 2021, several of the parties to the PCORC reached a multiparty settlement in principle, which was unopposed. The settlement resulted in an estimated revenue increase of $65.3 million or 3.1%. On June 1, 2021, the Washington Commission issued its Final Order approving and adopting the settlement and authorizing and requiring a power cost update through a compliance filing. On June 17, 2021, PSE filed a compliance filing with the Washington Commission with a revenue increase of $70.9 million or 3.3% due to the update on power costs with rates effective July 1, 2021. Per the 2022 GRC Final Order in Docket No. UE-220066, PCORC rates were set to zero as of January 11, 2023 and PSE agreed not to file a PCORC during 2023 and 2024, the two-year rate plan agreed to in the GRC settlement.

Revenue Decoupling Adjustment Mechanism

On July 8, 2020, the Washington Commission issued the final order in Dockets No. UE-190529 and UG-190530, which instructed PSE to extend the collection of amortization balances for electric decoupling delivery and fixed power cost sections originally filed through the annual May 2020 decoupling filing. The extension requires PSE to move amortization balances for electric decoupling as of August 31, 2020 to be collected from customers for a two-year period, instead of the originally approved one-year period. Additionally, through approving the electric cost of service, the final order approved the re-allocation of decoupling balances from Schedule 40 to the remaining electric decoupling groups.

On December 23, 2020, the Washington Commission approved PSE's filing to update Schedule 142 decoupling amortization rates, with an effective date of January 1, 2021, by zeroing out rates still effective past October 15, 2020 on tariff sheet Schedule 142-H, which was replaced by rates on tariff sheet Schedule 142-I effective October 15, 2020. PSE included a true up of the over-collection amounts for the period of October 15, 2020 through December 31, 2020 in PSE's annual May 2021 decoupling filing.

On June 1, 2021, the Washington Commission approved the multi-party settlement agreement which was filed within PSE's PCORC filing. As part of this settlement agreement, the electric annual fixed power cost allowed revenue was updated to reflect changes in the approved revenue requirement. The changes took effect on July 1, 2021.

On September 28, 2021, the Washington Commission approved 2019 GRC filing updated to PLR changes. As part of this filing, the annual electric and gas delivery cost allowed revenue was updated to reflect changes in the approved revenue requirement. The changes took effect on October 1, 2021.

On January 6, 2023, the Washington Commission approved the natural gas 2022 GRC filing. As part of this filing the annual gas delivery allowed revenue was updated to reflect changes in the approved revenue requirement. Additionally, the Commission approved the removal of the earnings test from the decoupling mechanism in accordance with RCW 80.28.425(6). The changes took effect on January 7, 2023.

On January 10, 2023, the Washington Commission approved the electric 2022 GRC filing. As part of this filing the annual electric delivery and fixed power cost allowed revenue was updated to reflect changes in the approved revenue requirement. Additionally, the Commission approved the removal of the earnings test from the decoupling mechanism in accordance with RCW 80.28.425(6). The changes took effect on January 11, 2023.

On December 31, 2022, PSE performed an analysis to determine if electric and natural gas decoupling revenue deferrals would be collected from customers within 24 months of the annual period, per ASC 980. If not, for GAAP purposes only, PSE would need to record a reserve against the decoupling revenue and regulatory asset balance. Once the reserve is probable of collection within 24 months from the end of the annual period, the reserve can be recognized as decoupling revenue. The

analysis indicated that electric and natural gas deferred revenue will be collected within 24 months of the annual period; therefore no reserve adjustment was booked to 2022 electric and natural gas decoupling revenue. This compares to $3.0 million of electric deferred revenue not being collected within 24 months of the annual period in 2021; therefore, a reserve adjustment was booked to 2021 electric decoupling revenue. Natural gas deferred revenue would be collected within 24 months of the annual period; therefore no reserve adjustment was booked to 2021 natural gas decoupling revenue.

Power Cost Adjustment Mechanism

PSE currently has a PCA mechanism that provides for the deferral of power costs that vary from the "power cost baseline" level of power costs. The "power cost baseline" levels are set, in part, based on normalized assumptions about weather and hydroelectric conditions. Excess power costs or savings are apportioned between PSE and its customers pursuant to the graduated scale set forth in the PCA mechanism and will trigger a surcharge or refund when the cumulative deferral trigger is reached.

Effective January 1, 2017, the following graduated scale is used in the PCA mechanism:

	Company's Share		Customers' Share	
Annual Power Cost Variability	Over	Under	Over	Under
Over or Under Collected by up to $17 million	100 %	100 %	— %	— %
Over or Under Collected by between $17 million - $40 million	35	50	65	50
Over or Under Collected beyond $40 + million	10	10	90	90

For the year ended December 31, 2022, in its PCA mechanism, PSE under recovered its allowable costs by $110.1 million of which $74.6 million was apportioned to customers and $1.5 million of interest was accrued on the deferred customer balance. This compares to an under recovery of allowable costs of $68.0 million, for the year ended December 31, 2021, of which $36.7 million was apportioned to customers and accrued $1.7 million of interest on the total deferred customer balance.

Power Cost Adjustment Clause

On July 8, 2020, the Washington Commission issued the final order in Dockets No. UE-190529 and UG-190530, which instructed PSE to remove Schedule 95 collection on decoupling allowed rates for Special Contracts, which are included in allowed rates under the Decoupling Schedule 142 effective October 15, 2020.

PSE exceeded the $20.0 million cumulative deferral balance in its PCA mechanism in 2020. The surcharging of deferrals can be triggered by the Company when the balance in the deferral account is a credit of $20.0 million or more. During 2020, actual power costs were higher than baseline power costs; thereby, creating an under-recovery of $76.1 million. Under the terms of the PCA's sharing mechanism for under-recovered power costs, PSE absorbed $32.1 million of the under-recovered amount, and customers were responsible for the remaining $44.0 million, or $46.0 million including interest. PSE filed to recover the deferred balance in Docket No. UE-210300, and the Washington Commission allowed the recovery effective December 1, 2021.

Additionally, PSE exceeded the $20.0 million cumulative deferral balance in its PCA mechanism in 2021. During 2021, actual power costs were higher than baseline power costs, thereby creating an under-recovery of $68.0 million. Under the terms of the PCA's sharing mechanism for under-recovered power costs, PSE absorbed $31.3 million of the under-recovered amount, and customers were responsible for the remaining $36.7 million, or $38.4 million including interest. On October 27, 2022, the Washington Commission approved PSE's 2021 PCA report that proposes to recover the deferred balance for 2021 PCA period by keeping the current rates and allowing recovery from January 1, 2023 through November 30, 2023.

Purchased Gas Adjustment Mechanism

On October 28, 2021, the Washington Commission approved PSE's request for PGA rates in Docket No. UG-210721, effective November 1, 2021. As part of that filing, PSE requested an annual revenue increase of $59.1 million; where PGA rates, under Schedule 101, increase annual revenue by $80.6 million, and the tracker rates under Schedule 106, decrease annual revenue by $21.5 million. Those annual 2021 PGA rate increases were set in addition to continuing the collection on the remaining balance of $69.4 million under Supplemental Schedule 106B, which were set, in effect, through September 30, 2023 per the 2019 GRC.

On October 27, 2022, the Washington Commission approved PSE's request for PGA rates in Docket No. UG-220715, effective November 1, 2022. As part of that filing, PSE requested an annual revenue increase of $155.3 million; where PGA rates, under Schedule 101, increase annual revenue by $142.1 million, and the tracker rates under Schedule 106, increase annual revenue by $13.2 million.

On November 15, 2022, the FERC approved a settlement of a counterparty, FERC Docket No. RP17-346. Under the terms, PSE was allocated $24.2 million related to PSE natural gas services which was recorded on December 31, 2022 and included below. The 2022 GRC order requires PSE to amortize the refund in 2023 as a credit against natural gas costs and therefore pass back the refund to customers through the PGA mechanism.

The following table presents the PGA mechanism balances and activity at December 31, 2022 and December 31, 2021:

Puget Energy and
Puget Sound Energy

(Dollars in Thousands)	At December 31,	At December 31,
PGA receivable balance and activity	2022	2021
PGA receivable beginning balance	$ 57,935	$ 87,655
Actual natural gas costs	457,950	364,775
Allowed PGA recovery	(496,879)	(396,236)
Interest	1,674	1,741
Refund from counterparty settlement	(24,216)	—
PGA (liability)/receivable ending balance	$ (3,536)	$ 57,935

Get to Zero Depreciation Deferral

On April 10, 2019, PSE filed an accounting petition with the Washington Commission, requesting authorization to defer depreciation expense associated with Get To Zero (GTZ) projects that were placed in service after June 30, 2018. The GTZ project consists of a number of short-lived technology upgrades. The depreciation expense associated with the GTZ projects with lives of 10 years or less that were placed in service after June 30, 2018, were deferred beginning May 1 per the petition request. For the year ended December 31, 2022 and December 31, 2021, PSE deferred $11.8 million and $6.6 million of depreciation expense for GTZ, respectively. In addition to the deferral of depreciation expense, PSE had also requested to defer carrying charges on the GTZ deferral, to be calculated utilizing the FERC quarterly rate of return. The 2022 GRC final order authorized recovery of all remaining GTZ depreciation and carrying charge balances as of December 2022. Finally, all GTZ deferrals ended as of December 2022.

Crisis Affected Customer Assistance Program

On April 6, 2020, PSE filed with the Washington Commission revisions to its currently effective electric and natural gas service tariffs. The purpose of this filing was to incorporate into PSE’s low-income tariff a new temporary bill assistance program, Crisis Affected Customer Assistance Program (CACAP-1) (Dockets No. UE-200331 and UG-200332), to mitigate the economic impact of the COVID-19 pandemic on PSE’s customers. CACAP-1 allowed PSE customers facing financial hardship due to COVID-19 to receive up to $1,000 in bill assistance. The program made available $11.0 million in unspent low income funds from prior years, therefore resulting in no rate impact, and supplemented other forms of financial assistance. CACAP-1 ran from April 13, 2020, to September 30, 2020.

On March 28, 2021, the Washington Commission approved PSE’s CACAP-2 (Dockets No. UE-210137 and UG-210138). With a program budget of $20.0 million for electric customers and $7.7 million for natural gas customers, CACAP-2, which ran from April 12, 2021, to March 29, 2022, provided up to $2,500 per year in bill assistance for arrearages for each qualifying low-income household.

On October 15, 2021, PSE submitted for the Washington Commission’s review and approval a Supplemental CACAP (Dockets No UE-210792 and UG-210793) filing to continue assistance for PSE customers facing financial hardship due to COVID-19. The Washington Commission approved the Supplemental CACAP program to be effective on November 15, 2021. The Supplemental CACAP utilized carry-over funds not expended in any prior years under PSE’s Schedule 129 Home Energy Lifeline Program (HELP), with a combined total budget of $34.5 million for both electric and natural gas residential customers (capped at $23.7 million and $10.8 million, respectively). Supplemental CACAP benefits offered to cover a qualifying residential customer’s past due balance, up to $2,500. PSE applied the Supplemental CACAP benefits automatically, with an opt-out option, in December 2021.

Storm Loss Deferral Mechanism

The Washington Commission has defined deferrable weather-related events and provided that costs in excess of the annual cost threshold may be deferred for qualifying damage costs that meet the modified Institute of Electrical and Electronics Engineers outage criteria for system average interruption duration index. For the year ended December 31, 2022, PSE incurred $32.2 million in weather-related electric transmission and distribution system restoration costs, of which the Company deferred $21.4 million and $0.2 million as regulatory assets related to storms that occurred in 2022 and 2021, respectively. This compares to $51.4 million incurred in weather-related electric transmission and distribution system restoration costs for the year ended December 31, 2021, of which the Company deferred $40.9 million and $0.2 million as regulatory assets related to storms that occurred in 2021 and 2020, respectively. Under the 2017 GRC Order, the storm loss deferral mechanism approved the following: (i) the cumulative annual cost threshold for deferral of storms under the mechanism at $10.0 million; and (ii) qualifying events where the total qualifying cost is less than $0.5 million will not qualify for deferral and these costs will also not count toward the $10.0 million annual cost threshold.

Environmental Remediation

The Company is subject to environmental laws and regulations by the federal, state and local authorities and is required to undertake certain environmental investigative and remedial efforts as a result of these laws and regulations. The Company has been named by the Environmental Protection Agency (EPA), the Washington State Department of Ecology and/or other third parties as potentially responsible at several contaminated sites and former manufactured gas plant sites. In accordance with the guidance of ASC 450, "Contingencies," the Company reviews its estimated future obligations and will record adjustments, if any, on a quarterly basis. Management believes it is probable and reasonably estimable that the impact of the potential outcomes of disputes with certain property owners and other potentially responsible parties will result in environmental remediation costs of $84.4 million for natural gas and $48.3 million for electric. The Company believes a significant portion of its past and future environmental remediation costs are recoverable from insurance companies, from third parties or from customers under a Washington Commission order. The Company is also subject to cost-sharing agreements with third parties regarding environmental remediation projects in Seattle, Tacoma, Everett, and Bellingham, Washington.

As of December 31, 2022, the Company's share of future remediation costs is estimated to be approximately $61.5 million. The Company's deferred electric environmental costs are $51.5 million and $52.2 million at December 31, 2022 and 2021, respectively, net of insurance proceeds. The Company's deferred natural gas environmental costs are $90.4 million and $75.8 million at December 31, 2022 and 2021, respectively, net of insurance proceeds.

(5) Dividend Payment Restrictions

The payment of dividends by PSE to Puget Energy is restricted by provisions of certain covenants applicable to long-term debt contained in PSE's electric and natural gas mortgage indentures. At December 31, 2022, approximately $1.4 billion of unrestricted retained earnings was available for the payment of dividends under the most restrictive mortgage indenture covenant.

Pursuant to the terms of the Washington Commission merger order, PSE may not declare or pay dividends if PSE's common equity ratio, calculated on a regulatory basis, is 44.0% or below except to the extent a lower equity ratio is ordered by the Washington Commission. Also, pursuant to the merger order, PSE may not declare or make any distribution unless on the date of distribution PSE's corporate credit/issuer rating is investment grade, or, if its credit ratings are below investment grade, PSE's ratio of earnings before interest, tax, depreciation and amortization (EBITDA) to interest expense for the most recently ended four fiscal quarter periods prior to such date is equal to or greater than 3.0 to 1.0. The common equity ratio, calculated on a regulatory basis, was 48.1% at December 31, 2022, and the EBITDA to interest expense was 5.0 to 1.0 for the twelve months ended December 31, 2022.

PSE's ability to pay dividends is also limited by the terms of its credit facilities, pursuant to which PSE is not permitted to pay dividends during any Event of Default (as defined in the facilities), or if the payment of dividends would result in an Event of Default, such as failure to comply with certain financial covenants.

Puget Energy's ability to pay dividends is also limited by the merger order issued by the Washington Commission. Pursuant to the merger order, Puget Energy may not declare or make a distribution unless on such date Puget Energy's ratio of consolidated EBITDA to consolidated interest expense for the four most recently ended fiscal quarters prior to such date is equal to or greater than 2.0 to 1.0. Puget Energy's EBITDA to interest expense was 3.7 to 1.0 for the twelve months ended December 31, 2022.

At December 31, 2022, the Company was in compliance with all applicable covenants, including those pertaining to the payment of dividends.

(6) Utility Plant

The following table presents electric, natural gas and common utility plant classified by account:

Utility Plant	Estimated Useful Life[1]	Puget Energy		Puget Sound Energy	
		December 31,		December 31,	
(Dollars in Thousands)	(Years)	2022	2021	2022	2021
Distribution plant	7-65	$ 7,886,665	$ 7,488,629	$ 9,406,017	$ 9,026,042
Production plant	3-90	3,131,578	3,147,987	3,780,910	3,815,599
Transmission plant	44-75	1,576,916	1,556,666	1,683,737	1,663,559
General plant	5-75	735,298	746,758	760,094	773,662
Intangible plant (including capitalized software)[2]	3-50	755,430	797,691	745,973	788,240
Plant acquisition adjustment	N/A	242,826	242,826	282,792	282,792
Underground storage	25-60	45,305	43,391	58,716	56,820
Liquefied natural gas storage	25-50	12,628	12,628	14,498	14,498
Plant held for future use	N/A	46,079	46,020	46,232	46,172
Recoverable Cushion Gas	N/A	8,784	8,655	8,784	8,655
Plant not classified	N/A	723,383	316,933	723,383	316,933

Finance leases, net of accumulated amortization[3]	N/A	99,967	105,020	99,967	105,020
Less: accumulated provision for depreciation		(4,341,789)	(4,031,458)	(6,688,033)	(6,416,246)
Subtotal		$ 10,923,070	$ 10,481,746	$ 10,923,070	$ 10,481,746
Construction work in progress		861,801	870,204	861,801	870,204
Net utility plant		$ 11,784,871	$ 11,351,950	$ 11,784,871	$ 11,351,950

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1. *Estimated Useful Life years have been approved in the 2022 GRC.*
2. *Intangible assets include capitalized software and franchise agreements with useful lives ranging between 3-10 years and 10-50 years, respectively.*
3. *At December 31, 2022, and 2021, accumulated amortization of finance leases at Puget Energy and PSE was $7.3 million and $2.6 million, respectively.*

Jointly owned generating plant service costs are included in utility plant service cost at the Company's ownership share. The Company provides financing for its ownership interest in the jointly owned utility plants. The following tables indicate the Company’s percentage ownership and the extent of the Company’s investment in jointly owned generating plants in service at December 31, 2022. These amounts are also included in the Utility Plant table above, with the exception of Puget Energy's portion of the Tacoma LNG facility, which is reported in the Puget Energy "Other property and investments" financial statement line item. The Company's share of fuel costs and operating expenses for plant in service are included in the corresponding accounts in the Consolidated Statements of Income.

Puget Energy

Jointly Owned Generating Plants (Dollars in Thousands)	Energy Source (Fuel)	Company’s Ownership Share	Plant in Service at Cost	Construction Work in Progress	Accumulated Depreciation
Colstrip Units 3 & 4	Coal	25.00%	$ 321,767	$ —	$ (176,847)
Frederickson 1	Natural Gas	49.85	63,348	—	(21,894)
Jackson Prairie	Natural Gas	33.34	44,708	837	(12,178)
Tacoma LNG	Natural Gas	various	494,795	2,936	(10,922)

Puget Sound Energy

Jointly Owned Generating Plants (Dollars in Thousands)	Energy Source (Fuel)	Company’s Ownership Share	Plant in Service at Cost	Construction Work in Progress	Accumulated Depreciation
Colstrip Units 3 & 4	Coal	25.00 %	$ 579,019	$ —	$ (434,099)
Frederickson 1	Natural Gas	49.85	69,415	—	(27,962)
Jackson Prairie	Natural Gas	33.34	58,716	837	(26,186)
Tacoma LNG	Natural Gas	various	245,690	503	(5,052)

In June 2019, Talen, the plant operator of Colstrip Units 1 and 2, announced a plan to shut down as of December 31, 2019. The Company retired Colstrip 1&2 from Utility Plant and transferred the unrecovered plant amount of $126.5 million to regulatory assets, offset by depreciation as included in base rates until the 2019 GRC became effective in October 2020. Consistent with the GRC settlement in 2017, monetization of the PTCs will fund the following: (i) Colstrip Community Transition Fund, (ii) unrecovered Colstrip plant and (iii) incurred decommissioning and remediation costs for Colstrip. At December 31, 2022, and December 31, 2021, the unrecovered plant for Colstrip 1&2 was fully offset with PTCs.

On September 2, 2022, PSE and Talen Energy reached an agreement to transfer PSE's ownership interest in Colstrip Units 3 and 4 to Talen Energy on December 31, 2025. Management evaluated Colstrip Units 3 and 4 and determined that the applicable held for sale accounting criteria were not met as of December 31, 2022. As such, Colstrip Units 3 and 4 are classified as Electric Utility Plant on the Company's balance sheet as of December 31, 2022.

Asset Retirement Obligation

The Company has recorded liabilities for steam generation sites, combustion turbine generation sites, wind generation sites, distribution and transmission poles, natural gas mains, liquefied natural gas storage sites, and leased facilities where disposal is governed by ASC 410-20 “Asset Retirement and Environmental Obligations" (ARO). The Company records its ARO liabilities for its electric transmission and distribution poles as well as gas distribution mains aligned with its underlying asset data with future estimates of retirements.

For the twelve months ended December 31, 2022, the Company reviewed the estimated remediation costs at Colstrip and determined no change was warranted for the Colstrip ARO liability for Colstrip Units 1 and 2 and Colstrip Units 3 and 4. For the twelve months ended December 31, 2021, the Company reviewed the estimated remediation costs at Colstrip and decreased the Colstrip ARO liability by $1.5 million for Colstrip Units 1 and 2, and $3.1 million for Colstrip Units 3 and 4. The 2021 decrease to Colstrip 1 and 2 is primarily due to remediation plans approved by the Montana Department of Environmental Quality under a 2012 settlement between the plant operator and the state for the remaining sites at Colstrip. The plant operator previously contested the approved plan for Colstrip Units 1 and 2 under the defined process in the settlement with the state and reached a settlement agreement regarding the ability to still present another option under the settlement terms and conditions. The Company had previously recorded these incremental costs in 2020 for remediation work on the older ponds under ASC 410-20 “Asset Retirement and Environmental Obligations" and ASC 410-30 "Environmental Remediation". For the twelve months ended December 31, 2022 and 2021, the Company also recorded relief of ARO and environmental remediation liability of $6.9 million and $13.1 million, respectively.

In addition, the Company recorded Tacoma LNG facility ARO liability of $3.9 million and $3.8 million for PSE and $3.8 million and $3.7 million for Puget LNG as of December 31, 2022 and December 31, 2021, respectively. The 2022 and 2021 increases to the Tacoma LNG facility ARO liabilities are primarily due to continued construction of the plant. In 2022, the ARO liability associated with the Tacoma LNG facility was fully recorded as construction was essentially complete and commissioning activities are on-going.

Puget Energy and Puget Sound Energy	December 31,	
(Dollars in Thousands)	2022	2021
Asset retirement obligation at beginning of the period	$ 209,041	$ 216,163
Relief of liability	(6,867)	(13,146)
Revisions in estimated cash flows	1,519	(46)
Accretion expense	5,713	6,070
Asset retirement obligation at end of period[1]	$ 209,406	$ 209,041

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1. *Asset retirement obligations include $3.8 million and $3.7 million for Puget LNG held only at Puget Energy as of December 31, 2022, and 2021, respectively.*

The Company has identified the following obligations, as defined by ASC 410, “ARO,” which were not recognized because the liability for these assets cannot be reasonably estimated at December 31, 2022:

- A legal obligation under Federal Dangerous Waste Regulations to dispose of asbestos-containing material in facilities that are not scheduled for remodeling, demolition or sales. The disposal cost related to these facilities could not be measured since the retirement date is indeterminable; therefore, the liability cannot be reasonably estimated;
- An obligation under Washington state law to decommission the wells at the Jackson Prairie natural gas storage facility upon termination of the project. Since the project is expected to continue as long as the Northwest pipeline continues to operate, the liability cannot be reasonably estimated;
- An obligation to pay its share of decommissioning costs at the end of the functional life of the major transmission lines. The major transmission lines are expected to be used indefinitely; therefore, the liability cannot be reasonably estimated;
- A legal obligation under Washington state environmental laws to remove and properly dispose of certain under and above ground fuel storage tanks. The disposal costs related to under and above ground storage tanks could not be measured since the retirement date is indeterminable; therefore, the liability cannot be reasonably estimated;
- An obligation to pay decommissioning costs at the end of utility service franchise agreements to restore the surface of the franchise area. The decommissioning costs related to facilities at the franchise area could not be measured since the decommissioning date is indeterminable; therefore, the liability cannot be reasonably estimated; and
- A potential legal obligation may arise upon the expiration of an existing FERC hydropower license if the FERC orders the project to be decommissioned, although PSE contends that the FERC does not have such authority. Given the value of ongoing generation, flood control and other benefits provided by these projects, PSE believes that the potential for decommissioning is remote and cannot be reasonably estimated.

(7) Long-Term Debt

The following table presents outstanding long-term debt due dates and principal amounts, net of debt discount, issuance and other costs and fair value adjustments as of 2022 and 2021:

(Dollars in Thousands)			December 31,	
Series	Type	Due	2022	2021
Puget Sound Energy:				
7.150%	First Mortgage Bond	2025	$ 15,000	$ 15,000
7.200%	First Mortgage Bond	2025	2,000	2,000
7.020%	Senior Secured Note	2027	300,000	300,000
7.000%	Senior Secured Note	2029	100,000	100,000

3.900%	Pollution Control Bond	2031	138,460	138,460
4.000%	Pollution Control Bond	2031	23,400	23,400
5.483%	Senior Secured Note	2035	250,000	250,000
6.724%	Senior Secured Note	2036	250,000	250,000
6.274%	Senior Secured Note	2037	300,000	300,000
5.757%	Senior Secured Note	2039	350,000	350,000
5.795%	Senior Secured Note	2040	325,000	325,000
5.764%	Senior Secured Note	2040	250,000	250,000
4.434%	Senior Secured Note	2041	250,000	250,000
5.638%	Senior Secured Note	2041	300,000	300,000
4.300%	Senior Secured Note	2045	425,000	425,000
4.223%	Senior Secured Note	2048	600,000	600,000
3.250%	Senior Secured Note	2049	450,000	450,000
2.893%	Senior Secured Note	2051	450,000	450,000
4.700%	Senior Secured Note	2051	45,000	45,000
*	Debt discount, issuance cost and other	*	(37,095)	(39,141)
Total PSE long-term debt			$ 4,786,765	$ 4,784,719
Puget Energy:				
*	Fair value adjustment of PSE long-term debt	*	$ (148,341)	$ (156,849)
*	Revolving Credit Agreement	2027	34,300	33,300
3.650%	Senior Secured Note	2025	400,000	400,000
2.379%	Senior Secured Note	2028	500,000	500,000
4.100%	Senior Secured Note	2030	650,000	650,000
4.224%	Senior Secured Note	2032	450,000	—
*	Debt discount, issuance cost and other	*	(9,351)	(7,404)
Total Puget Energy long-term debt			$ 6,663,373	$ 6,203,766

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* *Not Applicable.*

PSE's senior secured notes will cease to be secured by the pledged first mortgage bonds on the date (the "Substitution Date") that all of the first mortgage bonds issued and outstanding under the electric or natural gas utility mortgage indenture have been retired. As of December 31, 2022, the latest maturity date of the first mortgage bonds, other than pledged first mortgage bonds, is December 22, 2025. On the Substitution Date, PSE will deliver to the trustee for PSE's senior secured notes substitute pledged first mortgage bonds to be issued under a new mortgage indenture. As a result, as of the Substitution Date PSE's outstanding senior secured notes and any future series of PSE's senior secured notes will be secured by substitute pledged first mortgage bonds.

Puget Energy Long-Term Debt

On June 14, 2021, Puget Energy issued $500.0 million of senior secured notes at an interest rate of 2.379%. The notes were issued for a period of 7 years, mature on June 15, 2028, and pay interest semi-annually on June 15 and December 15. Proceeds from the issuance of the notes were invested in short-term money market funds, then used to repay the Company’s $500.0 million 6.0% notes that matured on September 1, 2021.

On June 23, 2021, Puget Energy received an equity contribution from Puget Equico LLC, Puget Energy’s parent company. The proceeds from the equity contribution were used to pay off Puget Energy’s $210.0 million term loan on June 23, 2021.

On March 10, 2022, Puget Energy filed an S-3 Registration statement under which it may issue up to $1.0 billion aggregate principal amount of senior notes secured by Puget Energy's assets. As of the date of this report, $550.0 million was available to be issued. The shelf registration will expire in March 2025.

On March 17, 2022, Puget Energy issued $450.0 million of senior secured notes at an interest rate of 4.224%. The notes mature on March 15, 2032, and pay interest semi-annually on March 15 and September 15 of each year. Proceeds from the issuance of the notes were invested in short-term money market funds, and then used to repay Puget Energy's $450.0 million 5.625% notes that were originally scheduled to mature July 2022.

On April 28, 2022, Puget Energy redeemed the $450.0 million 5.625% senior secured notes due July 2022 and paid related expenses for a total redemption price of $457.2 million, which includes repayment of the $450.0 million principal amount and $7.2 million of accrued interest expense.

At December 31, 2022, Puget Energy maintained an $800.0 million credit facility. As of December 31, 2022, $118.6 million was drawn and outstanding under the facility, of which $34.3 million was classified as long-term debt and $84.3 million was classified as short-term debt.

Puget Sound Energy Long-Term Debt

On September 15, 2021, PSE issued $450.0 million of senior secured notes at an interest rate of 2.893%. The notes were issued for a period of 30 years, mature on September 15, 2051, and pay interest semi-annually on March 15 and September 15 of each year. The proceeds from the issuance will be used for repayment of commercial paper as well as general corporate purposes.

In August 2022, PSE filed an S-3 shelf registration statement under which it may issue up to $1.4 billion aggregate principal amount of senior notes secured by first mortgage bonds. As of the date of this report, $1.4 billion was available to be issued. The shelf registration will expire in August 2025.

Long-Term Debt Maturities

The principal amounts of long-term debt maturities for the next five years and thereafter are as follows:

(Dollars in Thousands)	2023	2024	2025	2026	2027	Thereafter	Total
Maturities of:							
PSE	$ —	$ —	$ 17,000	$ —	$ 300,000	$ 4,506,860	$ 4,823,860
Puget Energy	—	—	400,000	—	$ 34,300	1,600,000	2,034,300
Total long-term debt	$ —	$ —	$ 417,000	$ —	$ 334,300	$ 6,106,860	$ 6,858,160

(8) Liquidity Facilities and Other Financing Arrangements

As of December 31, 2022, and 2021, PSE had $357.0 million and $140.0 million in short-term debt outstanding, respectively. Outside of the consolidation of PSE’s short-term debt, Puget Energy had $118.6 million drawn and outstanding under its credit facility, of which $34.3 million was classified as long-term debt and $84.3 million was classified as short-term debt. PSE’s weighted-average interest rate on short-term debt, including borrowing rate, commitment fees and the amortization of debt issuance costs, during 2022 and 2021 was 6.1% and 1.6%, respectively. As of December 31, 2022, PSE and Puget Energy had several committed credit facilities that are described below.

Puget Sound Energy

Credit Facility

On May 16, 2022, PSE entered into a new $800.0 million credit facility to replace the existing facility. The terms and conditions, including fees, financial covenant, expansion feature and credit spreads remain substantially the same. The base interest rate on loans has changed to the Secured Overnight Financing Rate (SOFR), as the London Interbank Offer Rate (LIBOR) is being discontinued in 2023. The proceeds of the PSE credit facility are to be used for general corporate purposes. The maturity date of the credit facility is May 14, 2027. The credit facility includes a swingline feature allowing same day availability on borrowings up to $75.0 million and has an expansion feature which, upon receipt of commitments from one or more lenders, could increase the total size of the facility up to $1.4 billion.

The credit agreement is syndicated among numerous lenders and contains usual and customary affirmative and negative covenants that, among other things, place limitations on PSE's ability to transact with affiliates, make asset dispositions and investments or permit liens to exist. The credit agreement also contains a leverage ratio that requires the ratio of (a) total funded indebtedness to (b) total capitalization to be 65% or less at all times. PSE certifies its compliance with such covenants to participating banks each quarter. As of December 31, 2022, PSE was in compliance with all applicable covenant ratios.

The credit agreement allows PSE to borrow at a prime based rate or to make floating rate advances at the SOFR, in either case, plus a spread that is based upon PSE's credit rating. PSE must pay a commitment fee on the unused portion of the credit facility. The spreads and the commitment fee depend on PSE's credit ratings. As of the date of this report, interest was calculated as SOFR plus 0.10% SOFR adjustment plus 1.25% spread over the adjusted SOFR rate and the commitment fee was 0.175%.

As of December 31, 2022, no amount was drawn under PSE's credit facility and $357.0 million was outstanding under the commercial paper program. Outside of the credit agreement, PSE had a $2.3 million letter of credit in support of a long-term transmission contract and had $28.0 million issued under a standby letter of credit in support of natural gas purchases.

Demand Promissory Note

In 2006, PSE entered into a revolving credit facility with Puget Energy, in the form of a credit agreement and a demand promissory note pursuant to which PSE may borrow up to $30.0 million from Puget Energy subject to approval by Puget Energy. Under the terms of the promissory note, PSE pays interest on the outstanding borrowings based on the lower of the weighted-average interest rates of PSE’s outstanding commercial paper or PSE’s senior unsecured revolving credit facility. Absent such borrowings, interest is charged at one-month LIBOR plus 0.25%. As of December 31, 2022, there was no outstanding balance under the promissory note.

Puget Energy

Credit Facility

On May 16, 2022, Puget Energy entered into a new $800.0 million credit facility to replace the existing facility. The terms and conditions, including fees, financial covenant, expansion feature and credit spreads remain substantially the same. The base interest rate on loans has changed to the SOFR, as the LIBOR is being discontinued in 2023. The proceeds of the PE credit facility are to be used for general corporate purposes. The maturity date of the credit facility is May 14, 2027. The Puget Energy revolving senior secured credit facility also has an accordion feature, upon receipt of commitments from one or more lenders, could increase the size of the facility up to $1.3 billion.

The revolving senior secured credit facility allows Puget Energy to borrow based on a prime based rate or SOFR, in either case, plus a spread based on Puget Energy's credit ratings. Puget Energy must pay a commitment fee on the unused portion of the facility. As of December 31, 2022, there was $118.6 million drawn and outstanding under the facility, of which $34.3 million was classified as long-term debt and $84.3 million was classified as short-term debt. As of the date of this report, interest was calculated as SOFR plus 0.10% SOFR adjustment plus 1.75% spread over the adjusted SOFR rate and the commitment fee was 0.275%.

The revolving senior secured credit facility contains usual and customary affirmative and negative covenants. The credit agreement also contains a leverage ratio that requires the ratio of (a) total funded indebtedness to (b) total capitalization to be 65% or less at all times. As of December 31, 2022, Puget Energy was in compliance with all applicable covenants.

On September 26, 2022, PE borrowed $50.0 million on the credit facility and contributed the proceeds to PSE as an equity contribution. The equity proceeds were used for general corporate purposes.

(9) Leases

PSE has operating leases for buildings for corporate offices and operations, real estate for operating facilities and the PSE and PLNG LNG facility, land for our wind farms, and vehicles for PSE’s fleet. Finance leases represent office printers and office buildings. The leases have remaining lease terms of less than a year to 47 years. PSE's right-of-use (ROU) assets and lease liabilities include options to extend leases when it is reasonably certain that PSE will exercise that option.

During 2021, mechanical completion was achieved for the Puget LNG facility which triggered an increase in the lease payments for the Port of Tacoma lease. This remeasurement resulted in an increase of the operating lease ROU asset and operating lease liabilities of $26.3 million, of which $0.4 million was recorded in current operating lease liabilities and $25.9 million was recorded in operating lease liabilities. Additionally, two finance leases commenced for service center facilities in Kent and Puyallup, Washington. The Kent lease has a term of 20 years and resulted in an increase of electric utility plant and finance lease liabilities of $45.1 million, of which $1.0 million was recorded in other current liabilities and $44.1 million was recorded in finance lease liabilities, respectively. The Puyallup lease has a term of 20 years and resulted in an increase in common utility plant and finance lease liabilities of $61.3 million, of which $0.4 million was recorded in other current liabilities and $59.9 million was recorded in finance lease liabilities.

During 2022, there were no material changes regarding the Company's leases.

The components of lease cost were as follows:

Puget Energy and Puget Sound Energy (Dollars in Thousands)	Year Ended December 31, 2022	Year Ended December 31, 2021
Finance lease cost:		
Amortization of right-of-use asset	$ 2,465	$ 1,291
Interest on lease liabilities	2,482	358
Total finance lease cost	$ 4,947	$ 1,649
Operating lease cost[1]	$ 23,984	$ 23,983

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1. *Includes $1.5 million and $1.4 million allocated to PLNG at Puget Energy related to the Port of Tacoma lease or both of the years ended December 31, 2022 and December 31, 2021, respectively.*

Supplemental cash flow information related to leases was as follows:

Puget Energy and Puget Sound Energy (Dollars in Thousands)	Year Ended December 31, 2022	Year Ended December 31, 2021
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flow for operating leases	$ 16,574	$ 16,440
Investing cash flow for operating leases[1]	7,410	7,543
Operating cash flow for finance leases	2,482	358
Financing cash flow for finance leases	2,465	1,291
Non-cash disclosure upon commencement of new lease		
Right-of-use assets obtained in exchange for new operating lease liabilities	$ 5,338	$ 4,820
Right-of-use assets obtained in exchange for new finance lease liabilities	—	105,176
Non-cash disclosure upon modification of existing lease		
Modification of operating lease right-of-use assets	$ 21,068	$ 26,287

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[1] *Includes $1.5 million and $1.4 million allocated to PLNG at Puget Energy related to the Port of Tacoma lease for both of the years ended December 31, 2022 and*

December 31, 2021, respectively.

Supplemental balance sheet information related to leases was as follows:

Puget Energy and Puget Sound Energy (Dollars in Thousands)	At December 31, 2022	At December 31, 2021
Operating Leases		
Operating lease right-of-use asset	$ 193,509	$ 184,957
Operating leases liabilities current	$ 20,342	$ 20,398
Operating lease liabilities long-term	181,265	172,510
Total operating lease liabilities:	$ 201,607	$ 192,908
Finance Leases		
Common plant	$ 58,391	$ 61,227
Electric plant	41,576	43,793
Total finance lease assets	$ 99,967	$ 105,020
Other current liabilities	$ 3,167	$ 1,742
Finance lease liabilities	102,518	105,303
Total finance lease liabilities	$ 105,685	$ 107,045
Weighted Average Remaining Lease Term		
Operating leases	22.00 Years	22.80 Years
Finance leases	19.10 Years	20.15 Years
Weighted Average Discount Rate		
Operating leases	3.62 %	3.27 %
Finance leases	3.07 %	3.07 %

The following table summarizes the Company's estimated future minimum lease payments as of December 31, 2022:

Puget Energy and Puget Sound Energy (Dollars in Thousands)	Future Minimum Lease Payments	
At December 31,	Operating Leases	Finance Leases
2023	$ 23,676	$ 6,383
2024	23,232	6,408
2025	21,887	6,534
2026	21,472	6,591
2027	21,047	6,670
Thereafter	172,969	109,882
Total lease payments	$ 284,283	$ 142,468
Less imputed interest	(82,676)	(36,783)
Total net present value	$ 201,607	$ 105,685

(10) Accounting for Derivative Instruments and Hedging Activities

PSE employs various energy portfolio optimization strategies, but is not in the business of assuming risk for the purpose of realizing speculative trading revenue. The nature of serving regulated electric customers with its portfolio of owned and contracted electric generation resources exposes PSE and its customers to some volumetric and commodity price risks within the sharing mechanism of the Power Cost Adjustment. Therefore, wholesale market transactions and PSE's related hedging strategies are focused on reducing costs and risks where feasible, thus reducing volatility in costs in the portfolio. In order to manage its exposure to the variability in future cash flows for forecasted energy transactions, PSE utilizes a programmatic hedging strategy which extends out three years. PSE's hedging strategy includes a risk-responsive component for the core natural gas portfolio, which utilizes quantitative risk-based measures with defined objectives to balance both portfolio risk and hedge costs.

PSE's energy risk portfolio management function monitors and manages these risks using analytical models and tools. In order to manage risks effectively, PSE enters into forward physical electric and natural gas purchase and sale agreements, fixed-for-floating swap contracts, and commodity call/put options. Currently, the Company does not apply cash flow hedge accounting, and therefore records all mark-to-market gains or losses through earnings.

The Company manages its interest rate risk through the issuance of mostly fixed-rate debt with varied maturities. The Company utilizes internal cash from operations, borrowings under its commercial paper program, and its credit facilities to meet short-term funding needs. The Company may enter into swap instruments or other financial hedge instruments to manage the interest rate risk associated with these debts.

The following table presents the volumes, fair values and classification of the Company's derivative instruments recorded on the balance sheets:

Puget Energy and Puget Sound Energy	Year Ended December 31,					
(Dollars in Thousands)	Volumes (millions)		Assets[1]		Liabilities[2]	
	2022	2021	2022	2021	2022	2021
Electric portfolio derivatives	*	*	$ 337,703	$ 74,829	$ 87,120	$ 85,424
Natural gas derivatives (MMBtus)[3]	322	347	343,947	79,578	56,222	18,850
Total derivative contracts			$ 681,650	$ 154,407	$ 143,342	$ 104,274
Current			587,029	128,210	124,976	63,309
Long-term			94,621	26,197	18,366	40,965
Total derivative contracts			$ 681,650	$ 154,407	$ 143,342	$ 104,274

1. *Balance sheet classification: Current and Long-term Unrealized gain on derivative instruments.*
2. *Balance sheet classification: Current and Long-term Unrealized loss on derivative instruments.*
3. *All fair value adjustments on derivatives relating to the natural gas business have been deferred in accordance with ASC 980, "Regulated Operations," due to the PGA mechanism. The net derivative asset or liability and offsetting regulatory liability or asset are related to contracts used to economically hedge the cost of physical gas purchased to serve natural gas customers.*

* *Electric portfolio derivatives consist of electric generation fuel of 234.9 million One Million British Thermal Units (MMBtus) and purchased electricity of 5.3 million megawatt hours (MWhs) at December 31, 2022, and 238.0 million MMBtus and 8.1 million MWhs at December 31, 2021.*

It is the Company's policy to record all derivative transactions on a gross basis at the contract level without offsetting assets or liabilities. The Company generally enters into transactions using the following master agreements: WSPP, Inc. (WSPP) agreements, which standardize physical power contracts; International Swaps and Derivatives Association (ISDA) agreements, which standardize financial natural gas and electric contracts; and North American Energy Standards Board (NAESB) agreements, which standardize physical natural gas contracts. The Company believes that such agreements reduce credit risk exposure because such agreements provide for the netting and offsetting of monthly payments as well as the right of set-off in the event of counterparty default. The set-off provision can be used as a final settlement of accounts which extinguishes the mutual debts owed between the parties in exchange for a new net amount. For further details regarding the fair value of derivative instruments, see Note 11, "Fair Value Measurements", to the consolidated financial statements included in Item 8 of this report.

The following tables present the potential effect of netting arrangements, including rights of set-off associated with the Company's derivative assets and liabilities:

Puget Energy and Puget Sound Energy	December 31, 2022					
				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(Dollars in Thousands)	Gross Amount Recognized in the Consolidated Balance Sheet[1]	Gross Amounts Offset in the Consolidated Balance Sheet	Net of Amounts Presented in the Consolidated Balance Sheet	Commodity Contracts[2]	Cash Collateral Received/Pledged	Net Amount
Assets:						
Energy derivative contracts	$ 681,650	$ —	$ 681,650	$ (125,334)	$ —	$ 556,316
Liabilities:						
Energy derivative						

contracts	143,342	—	143,342	(125,334)	(5,661)	12,347

Puget Energy and
Puget Sound Energy

December 31, 2021				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(Dollars in Thousands)	Gross Amount Recognized[1]	Gross Amounts Offset in the Consolidated Balance Sheet	Net of Amounts Presented in the Consolidated Balance Sheet	Commodity Contracts[2]	Cash Collateral Received/Pledged	Net Amount
Assets						
Energy Derivative Contracts	$ 154,407	$ —	$ 154,407	$ (40,833)	$ —	$ 113,574
Liabilities						
Energy Derivative Contracts	104,274	—	104,274	(40,833)	(1,743)	61,698

1. *All derivative contract deals are executed under ISDA, NAESB, and WSPP master agreements with right of set-off.*
2. *Amounts reflect netting by Counterparty and right of set-off.*

The following tables present the effect and locations of the realized and unrealized gains (losses) of the Company's derivatives recorded on the statements of income:

Puget Energy and Puget Sound Energy		Year Ended December 31,		
(Dollars in Thousands)	Location	2022	2021	2020
Gas for Power Derivatives:				
Unrealized	Unrealized gain (loss) on derivative instruments, net	$ 61,761	$ 26,686	$ 5,534
Realized	Electric generation fuel	158,550	76,504	5,246
Power Derivatives:				
Unrealized	Unrealized gain (loss) on derivative instruments, net	199,416	(12,901)	(32,341)
Realized	Purchased electricity	20,917	(3,044)	(14,958)
Total gain (loss) recognized in income on derivatives		$ 440,644	$ 87,245	$ (36,519)

The Company is exposed to credit risk primarily through buying and selling electricity and natural gas to serve its customers. Credit risk is the potential loss resulting from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for, among other things, counterparty credit analysis, exposure measurement, and exposure monitoring and mitigation.

The Company monitors counterparties for significant swings in credit default swap rates, credit rating changes by external rating agencies, ownership changes or financial distress. Where deemed appropriate, the Company may request collateral or other security from its counterparties to mitigate potential credit default losses. Criteria employed in this decision include, among other things, the perceived creditworthiness of the counterparty and the expected credit exposure.

It is possible that volatility in energy commodity prices could cause the Company to have material credit risk exposure with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. However, as of December 31, 2022, approximately 99.4% of the Company's energy portfolio exposure, excluding normal purchase normal sale (NPNS) transactions, is with counterparties that are rated investment grade by rating agencies and 0.6% are either rated below investment grade or not rated by rating agencies. The Company assesses credit risk internally for counterparties that are not rated by the major rating agencies.

The Company computes credit reserves at a master agreement level by counterparty. The Company considers external credit ratings and market factors in the determination of reserves, such as credit default swaps and bond spreads. The Company recognizes that external ratings may not always reflect how a market participant perceives a counterparty's risk of default. The Company uses both default factors published by Standard & Poor's and factors derived through analysis of market risk, which reflect the application of an industry standard recovery rate. The Company selects a default factor by counterparty at an aggregate master agreement level based on a weighted average default tenor for that counterparty's deals. The default tenor is determined by weighting the fair value and contract tenors for all deals for each counterparty to derive an average value. The default factor used is dependent upon whether the counterparty is in a net asset or a net liability position after applying the master agreement levels.

The Company applies the counterparty's default factor to compute credit reserves for counterparties that are in a net asset position. The Company calculates a non-performance risk on its derivative liabilities by using its estimated incremental borrowing rate over the risk-free rate. Credit reserves are netted against unrealized gain (loss) positions. As of December 31, 2022, the Company was in a net liability position with the majority of counterparties, so the default factors of counterparties did not have a significant impact on reserves for the period. The majority of the Company's derivative contracts are with financial institutions and other utilities operating within the Western Electricity Coordinating Council. PSE also transacts power futures contracts on the Intercontinental Exchange (ICE), and natural gas contracts on the ICE NGX exchange platform. Execution of contracts on ICE requires the daily posting of margin calls as collateral through a futures and clearing agent. As of December 31, 2022, PSE had cash posted as collateral of $23.2 million related to contracts executed on the ICE platform. In August 2022, PSE entered into a standby letter of credit agreement with TD Bank allowing standby letter of credit postings of up to $50.0 million as a condition of transacting on the ICE NGX platform. As of December 31, 2022, PSE had $33.0 million in cash posted with ICE NGX and $28.0 million issued under the standby letter of credit agreement. PSE did not trigger any collateral requirements with any of its counterparties nor were any of PSE's counterparties required to post collateral resulting from credit rating downgrades during the twelve months ended December 31, 2022.

The following table presents the aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position and the amount of additional collateral the Company could be required to post:

Puget Energy and Puget Sound Energy (Dollars in Thousands)	December 31,					
	2022			2021		
Contingent Feature	Fair Value[1] Liability	Posted Collateral	Contingent Collateral	Fair Value[1] Liability	Posted Collateral	Contingent Collateral
Credit rating[2]	$ 3,157	$ —	$ 3,157	$ 52,537	$ —	$ 52,537
Requested credit for adequate assurance	4,157	—	—	9,380	—	—
Forward value of contract[3]	5,661	56,200	N/A	1,743	12,782	N/A
Total	$ 12,975	$ 56,200	$ 3,157	$ 63,660	$ 12,782	$ 52,537

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1. *Represents the derivative fair value of contracts with contingent features for counterparties in net derivative liability positions. Excludes NPNS, accounts payable and accounts receivable.*
2. *Failure by PSE to maintain an investment grade credit rating from each of the major credit rating agencies provides counterparties a contractual right to demand collateral.*
3. *Collateral requirements may vary, based on changes in the forward value of underlying transactions relative to contractually defined collateral thresholds.*

(11) Fair Value Measurements

ASC 820 established a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy categorizes the inputs into three levels with the highest priority given to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority given to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 - Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities. Equity securities that are also classified as cash equivalents are considered Level 1 if there are unadjusted quoted prices in active markets for identical assets or liabilities.

Level 2 - Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. Instruments in this category include non-exchange-traded derivatives such as over-the-counter forwards and options.

Level 3 - Pricing inputs include significant inputs that have little or no observability as of the reporting date. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities measured at fair value are classified in their entirety in the appropriate fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. The Company primarily determines fair value measurements classified as Level 2 or Level 3 using a combination of the income and market valuation approaches. The process of determining the fair values is the responsibility of the derivative accounting department which reports to the Controller and Principal Accounting Officer. Inputs used to estimate the fair value of forwards, swaps and options include market-price curves, contract terms and prices, credit-risk adjustments, and discount factors. Additionally, for options, the Black-Scholes option valuation model and implied market volatility curves are used. Inputs used to estimate fair value in industry-standard models are categorized as Level 2 inputs as substantially all assumptions and inputs are observable in active

markets throughout the full term of the instruments. On a daily basis, the Company obtains quoted forward prices for the electric and natural gas markets from an independent external pricing service.

The Company considers its electric and natural gas contracts as Level 2 derivative instruments as such contracts are commonly traded as over-the-counter forwards with indirectly observable price quotes. However, certain energy derivative instruments with maturity dates falling outside the range of observable price quotes or that are transacted at illiquid delivery locations are classified as Level 3 in the fair value hierarchy. Management's assessment is based on the trading activity in real-time and forward electric and natural gas markets. Each quarter, the Company confirms the validity of pricing-service quoted prices used to value Level 2 commodity contracts with the actual prices of commodity contracts entered into during the most recent quarter.

Assets and Liabilities with Estimated Fair Value

The carrying values of cash and cash equivalents, restricted cash, and short-term debt as reported on the balance sheet are reasonable estimates of their fair value due to the short-term nature of these instruments and are classified as Level 1 in the fair value hierarchy. The carrying value of other investments of $55.0 million and $53.2 million at December 31, 2022, and 2021, respectively, are included in "Other property and investments" on the balance sheet. These values are also reasonable estimates of their fair value and classified as Level 2 in the fair value hierarchy as they are valued based on market rates for similar transactions.

The fair value of long-term notes were estimated using the discounted cash flow method with U.S. Treasury yields and Company's credit spreads as inputs, interpolating to the maturity date of each issue.

The carrying values and estimated fair values were as follows:

Puget Energy		December 31, 2022		December 31, 2021	
(Dollars in Thousands)	Level	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial liabilities:					
Long-term debt (fixed-rate), net of discount[1]	2	$ 6,629,073	$ 6,149,797	$ 6,170,466	$ 7,769,896
Long-term debt (variable-rate), net of discount	2	34,300	34,300	33,300	33,300
Total		$ 6,663,373	$ 6,184,097	$ 6,203,766	$ 7,803,196

Puget Sound Energy		December 31, 2022		December 31, 2021	
(Dollars in Thousands)	Level	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial liabilities:					
Long-term debt (fixed-rate), net of discount[2]	2	$ 4,786,765	$ 4,379,010	$ 4,784,719	$ 6,145,639
Total		$ 4,786,765	$ 4,379,010	$ 4,784,719	$ 6,145,639

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1. *The carrying value includes debt issuances costs of $21.5 million and $22.7 million for December 31, 2022, and 2021, respectively, which are not included in fair value.*
2. *The carrying value includes debt issuances costs of $21.4 million and $22.8 million for December 31, 2022, and 2021, respectively, which are not included in fair value.*

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following tables present the Company's financial assets and liabilities by level, within the fair value hierarchy, that were accounted for at fair value on a recurring basis and the reconciliation of the changes in the fair value of Level 3 derivatives in the fair value hierarchy:

Puget Energy and Puget Sound Energy	Fair Value December 31, 2022			Fair Value December 31, 2021		
(Dollars in Thousands)	Level 2	Level 3	Total	Level 2	Level 3	Total
Assets:						
Electric Derivative Instruments	$ 218,610	$ 119,093	$ 337,703	$ 68,011	$ 6,818	$ 74,829
Gas Derivative Instruments	342,988	959	343,947	79,526	52	79,578
Total derivative assets	$ 561,598	$ 120,052	$ 681,650	$ 147,537	$ 6,870	$ 154,407
Liabilities:						

Electric Derivative Instruments	$ 84,105	$ 3,015	$ 87,120	$ 35,854	$ 49,570	$ 85,424
Gas Derivative Instruments	55,136	1,086	56,222	16,678	2,172	18,850
Total derivative liabilities	$ 139,241	$ 4,101	$ 143,342	$ 52,532	$ 51,742	$ 104,274

Puget Energy and Puget Sound Energy Level 3 Roll-Forward Net Asset (Liability)	Year Ended December 31,								
	2022			2021			2020		
(Dollars in Thousands)	Electric	Natural Gas	Total	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Balance at beginning of period	$ (42,752)	$ (2,120)	$ (44,872)	$ (23,718)	$ (1,135)	$ (24,853)	$ (3,379)	$ 1,282	$ (2,09
Changes during period:									
Realized and unrealized energy derivatives									
Included in earnings[1]	180,533	—	180,533	(15,839)	—	(15,839)	(23,559)	—	(23,55
Included in regulatory assets / liabilities	—	301	301	—	(1,749)	(1,749)	—	(1,049)	(1,04
Settlements[2]	(21,972)	1,369	(20,603)	(3,195)	764	(2,431)	3,220	(1,368)	1,85
Transferred into Level 3	—	—	—	—	—	—	—	—	–
Transferred out Level 3	269	323	592	—	—	$ —	—	—	$ –
Balance at end of period	$ 116,078	$ (127)	$ 115,951	$ (42,752)	$ (2,120)	$ (44,872)	$ (23,718)	$ (1,135)	$ (24,85

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1. *Income Statement classification: Unrealized gain (loss) on derivative instruments, net. Includes unrealized gains (losses) on derivatives still held in position as of the reporting date for electric derivatives of $147.1 million, $(21.6) million and $(21.3) million for the years ended December 31, 2022, 2021, and 2020, respectively.*

2. *The Company had no purchases or sales of options during the reported periods.*

Realized gains and losses on energy derivatives for Level 3 recurring items are included in energy costs in the Company's consolidated statements of income under purchased electricity, electric generation fuel or purchased natural gas when settled. Unrealized gains and losses on energy derivatives for Level 3 recurring items are included in net unrealized (gain) loss on derivative instruments in the Company's consolidated statements of income.

In order to determine which assets and liabilities are classified as Level 3, the Company receives market data from its independent external pricing service defining the tenor of observable market quotes. To the extent any of the Company's commodity contracts extend beyond what is considered observable as defined by its independent pricing service, the contracts are classified as Level 3. The actual tenor of what the independent pricing service defines as observable is subject to change depending on market conditions. Therefore, as the market changes, the same contract may be designated Level 3 one month and Level 2 the next, and vice versa. The changes of fair value classification into or out of Level 3 are recognized each month and reported in the Level 3 Roll-forward table above. The Company did not have any transfers between Level 2 and Level 1 during the years ended December 31, 2022, 2021, and 2020. The Company does transact at locations, or market price points, that are illiquid or for which no prices are available from the independent pricing service. In such circumstances the Company uses a more liquid price point and adjusts the price for transportation costs to the illiquid locations to serve as a proxy for market prices. Such transactions are classified as Level 3. The Company does not use internally developed models to make adjustments to significant unobservable pricing inputs.

The only significant unobservable input into the fair value measurement of the Company's Level 3 assets and liabilities is the forward price for electric and natural gas contracts.

Below are the forward price ranges for the Company's commodity contracts, as of December 31, 2022:

Puget Energy and Puget Sound Energy	Fair Value				Range		
(Dollars in Thousands)	Assets[1]	Liabilities[1]	Valuation Technique	Unobservable Input	Low	High	Weighted
Electricity	$ 119,093	$ 3,015	Discounted cash flow	Power Prices (per MWh)	$ 55.79	$ 291.03	$ 131.51
Natural Gas	$ 959	$ 1,086	Discounted cash flow	Natural Gas Prices (per MMBtu)	$ 3.84	$ 7.00	$ 4.87

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1 *The valuation techniques, unobservable inputs and ranges are the same for asset and liability positions.*

The significant unobservable inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. Consequently, significant increases or decreases in the forward prices of electricity or natural gas in isolation would result in a significantly higher or lower fair value for Level 3 assets and liabilities. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets. At December 31, 2022, a hypothetical 10% increase or decrease in market prices of natural gas and electricity would change the fair value of the Company's derivative portfolio, classified as Level 3 within the fair value hierarchy, by $37.6 million.

Long-Lived Assets Measured at Fair Value on a Nonrecurring Basis

Puget Energy records the fair value of its intangible assets in accordance with ASC 360, “Property, Plant, and Equipment,” (ASC 360). The fair value assigned to the power contracts was determined using an income approach comparing the contract rate to the market rate for power over the remaining period of the contracts incorporating non-performance risk. Management also incorporated certain assumptions related to quantities and market presentation that it believes market participants would make in the valuation. The fair value of the power contracts is amortized as the contracts settle.

ASC 360 requires long-lived assets to be tested for recoverability whenever events or changes in circumstances indicate that its carrying amount may not be recoverable. One such triggering event is a significant decrease in the forward market prices of power.

Puget Energy evaluated the triggering event criteria in ASC 360 during 2022 and 2021 and determined there was no indication of impairment of its power purchase contracts.

(12) Employee Investment Plans

The Company's Investment Plan is a qualified employee 401(k) plan, under which employee salary deferrals and after-tax contributions are used to purchase several different investment fund options. PSE’s contributions to the employee Investment Plan were $25.2 million, $23.6 million and $22.1 million for the years 2022, 2021, and 2020, respectively. The employee Investment Plan eligibility requirements are set forth in the plan documents.

Non-represented employees and United Association of Journeymen and Apprentices of the Plumbing and Pipefitting Industry (UA) represented employees hired before January 1, 2014, and International Brotherhood of Electrical Workers Local Union 77 (IBEW) represented employees hired before December 12, 2014, have the following company contributions:

1. For employees under the Cash Balance retirement plan formula, PSE will match 100% of an employee's contribution up to 6.0% of plan compensation each paycheck, and will make an additional year-end contribution equal to 1.0% of base pay.
2. For employees grandfathered under the Final Average Earning retirement plan formula, PSE will match 55.0% of an employee’s contribution up to 6.0% of plan compensation each paycheck.

Non-represented and UA-represented employees hired on or after January 1, 2014 along with IBEW-represented employees hired on or after December 12, 2014, will have access to the 401(k) plan. The two contribution sources from PSE are below:

1. 401(k) Company Matching: For non-represented, UA-represented and IBEW-represented employees PSE will match: 100% match on the first 3.0% of pay contributed and 50.0% match on the next 3.0% of pay contributed, such that an employee who contributes 6.0% of pay will receive 4.5% of pay in company match. Company matching will be immediately vested.
2. Company Contribution: For UA-represented employees will receive an annual company contribution of 4.0% of eligible pay placed in the Cash Balance retirement plan. Non-represented and IBEW-represented employees will receive an annual company contribution of 4.0% of eligible pay, placed either in the Investment Plan 401(k) plan or in PSE’s Cash Balance retirement plan. Non-represented and IBEW-represented employees will make a one-time election within 30 days of hire and direct that PSE put the 4.0% contribution either into the 401(k) plan or into an account in the Cash Balance retirement plan. The Company's 4.0% contribution will vest after three years of service.

(13) Retirement Benefits

PSE has a defined benefit pension plan (Qualified Pension Benefits) covering a substantial majority of PSE employees. For employees hired prior to 2014, pension benefits earned are a function of age, salary, years of service and, in the case of employees in the cash balance formula plan, the applicable annual interest crediting rates. Effective January 1, 2014, all new UA represented employees hired or rehired receive annual pay credits of 4.0% of eligible pay each year in the cash balance formula of the defined pension plan. Effective January 1, 2014 for non-represented employees, and December 12, 2014 for employees represented by the IBEW, newly hired or rehired employees receive annual employer contributions of 4.0% of eligible play each year into the cash balance formula of the defined benefit pension or 401k plan account. PSE also has a non-qualified Supplemental Executive Retirement Plan (SERP) for certain key senior management employees that closed to new participants in 2019. Effective 2019, PSE has an officer restoration benefit for new officers who join PSE or are promoted, such that company contributions under PSE’s applicable tax-qualified plan, which otherwise would have been credited if not for IRS limitations, are credited at 4.0% of earnings to an account with the Deferred Compensation Plan.

In addition to providing pension benefits, PSE provides legacy group health care and life insurance benefits (Other Benefits) for certain retired employees. These benefits are provided principally through an insurance company. The insurance premiums, paid primarily by retirees, are based on the benefits provided during the prior year. On June 11, 2019, the Company's Welfare Benefits Committee approved the termination of the Plan effective December 31, 2019, and the creation of a Retiree Health Reimbursement Account (HRA) Plan effective January 1, 2020.

Puget Energy's retirement plans were remeasured as a result of the merger in 2009, which represents the difference between Puget Energy and PSE's retirement plans. The components of service cost are included within utility operations and maintenance for PSE and within non-utility expense and other for Puget Energy while all non-service cost components are included in other income.

The following tables summarize the Company's change in benefit obligation, change in plan assets and amounts recognized in the Statements of Financial Position for the years ended December 31, 2022, and 2021:

Puget Energy and Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2022	2021	2022	2021	2022	2021
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 834,960	$ 849,383	$ 43,155	$ 46,742	$ 11,654	$ 12,114
Amendments	—	—	—	—	38	205
Service cost	26,351	26,888	557	456	217	155
Interest cost	24,263	22,381	1,253	1,183	311	302
Actuarial loss (gain)	(215,005)	(6,826)	(5,260)	828	(2,397)	(514)
Benefits paid	(80,226)	(55,831)	(7,659)	(6,054)	(808)	(803)
Medicare part D subsidy received	—	—	—	—	—	195
Administrative expense	(1,065)	(1,035)	—	—	—	—
Benefit obligation at end of period	$ 589,278	$ 834,960	$ 32,046	$ 43,155	$ 9,015	$ 11,654

Puget Energy and Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2022	2021	2022	2021	2022	2021
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 898,550	$ 834,655	$ —	$ —	$ 6,341	$ 5,918
Actual return on plan assets	(176,537)	102,787	—	—	(550)	1,005
Employer contribution	18,000	18,000	7,659	6,054	207	222
Benefits paid	(80,226)	(55,831)	(7,659)	(6,054)	(808)	(804)
Administrative expense	(1,254)	(1,061)	—	—	—	—
Fair value of plan assets at end of period	$ 658,533	$ 898,550	$ —	$ —	$ 5,190	$ 6,341
Funded status at end of period	$ 69,255	$ 63,590	$ (32,046)	$ (43,155)	$ (3,825)	$ (5,313)

Puget Energy and Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2022	2021	2022	2021	2022	2021
Amounts recognized in Consolidated Balance Sheet consist of:						
Noncurrent assets	$ 69,255	$ 63,590	$ —	$ —	$ —	$ —
Current liabilities	—	—	(3,532)	(2,822)	(252)	(280)
Noncurrent liabilities	—	—	(28,514)	(40,333)	(3,573)	(5,033)
Net assets (liabilities)	$ 69,255	$ 63,590	$ (32,046)	$ (43,155)	$ (3,825)	$ (5,313)

Puget Energy and Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2022	2021	2022	2021	2022	2021
Change in plan obligation and plan asset:						
Projected benefit obligation	$ 589,278	$ 834,960	$ 32,046	$ 43,155	$ 9,015	$ 11,654
Accumulated benefit obligation	582,538	823,418	29,763	40,773	8,929	11,549
Fair value of plan assets	658,533	898,550	—	—	5,190	6,341

The following tables summarize Puget Energy's and PSE's pension benefit amounts recognized in accumulated other comprehensive income (AOCI) for the years ended December 31, 2022, and 2021:

	Qualified	SERP	Other

Puget Energy	Pension Benefits		Pension Benefits		Benefits	
(Dollars in Thousands)	2022	2021	2022	2021	2022	2021
Amounts recognized in Accumulated Other Comprehensive Income consist of:						
Net loss (gain)	$ 31,213	$ 24,859	$ 1,563	$ 9,571	$ (1,964)	$ (525)
Prior service cost (credit)	—	—	289	578	259	242
Total	$ 31,213	$ 24,859	$ 1,852	$ 10,149	$ (1,705)	$ (283)

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2022	2021	2022	2021	2022	2021
Amounts recognized in Accumulated Other Comprehensive Income consist of:						
Net loss (gain)	$ 124,767	$ 127,111	$ 1,864	$ 10,103	$ (2,056)	$ (622)
Prior service cost (credit)	—	—	289	578	258	242
Total	$ 124,767	$ 127,111	$ 2,153	$ 10,681	$ (1,798)	$ (380)

The following tables summarize Puget Energy's and PSE's net periodic benefit cost for the years ended December 31, 2022, 2021, and 2020.

Puget Energy	Qualified Pension Benefits			SERP Pension Benefits			Other Benefits		
(Dollars in Thousands)	2022	2021	2020	2022	2021	2020	2022	2021	2020
Components of net periodic benefit cost:									
Service cost	$ 26,351	$ 26,888	$ 24,337	$ 557	$ 456	$ 756	$ 217	$ 155	$ 190
Interest cost	24,263	22,381	25,180	1,253	1,183	1,464	311	302	368
Expected return on plan assets	(51,014)	(48,239)	(49,902)	—	—	—	(379)	(355)	(389)
Amortization of prior service cost (credit)	—	(1,904)	(1,980)	289	349	349	22	6	—
Amortization of net loss (gain)	6,381	11,803	8,160	2,471	2,165	2,122	(29)	(39)	(82)
Net periodic benefit cost	$ 5,981	$ 10,929	$ 5,795	$ 4,570	$ 4,153	$ 4,691	$ 142	$ 69	$ 87

Puget Sound Energy	Qualified Pension Benefits			SERP Pension Benefits			Other Benefits		
(Dollars in Thousands)	2022	2021	2020	2022	2021	2020	2022	2021	2020
Components of net periodic benefit cost:									
Service cost	$ 26,351	$ 26,888	$ 24,337	$ 557	$ 456	$ 756	$ 217	$ 155	$ 190
Interest cost	24,263	22,381	25,180	1,253	1,183	1,464	311	302	368
Expected return on plan assets	(51,016)	(48,242)	(49,910)	—	—	—	(379)	(355)	(389)
Amortization of prior service cost (credit)	—	(1,513)	(1,573)	289	349	349	22	6	—
Amortization of net loss (gain)	15,080	21,862	19,043	2,648	2,344	2,385	(35)	(52)	(137)
Net periodic benefit cost	$ 14,678	$ 21,376	$ 17,077	$ 4,747	$ 4,332	$ 4,954	$ 136	$ 56	$ 32

The following tables summarize Puget Energy's and PSE's benefit obligations recognized in other comprehensive income (OCI) for the years ended December 31, 2022, and 2021:

Puget Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2022	2021	2022	2021	2022	2021
Other changes (pre-tax) in plan assets and benefit obligations recognized in other comprehensive income:						
Net loss (gain)	$ 12,735	$ (61,348)	$ (5,260)	$ 828	$ (1,468)	$ (1,164)

Amortization of net (loss) gain	(6,381)	(11,803)	(2,471)	(2,164)	29	39
Settlements, mergers, sales, and closures	—	—	(277)	(830)	—	—
Prior service cost (credit)	—	—	—	—	38	205
Amortization of prior service (cost) credit	—	1,904	(289)	(349)	(22)	(6)
Total change in other comprehensive income for year	$ 6,354	$ (71,247)	$ (8,297)	$ (2,515)	$ (1,423)	$ (926)

Puget Sound Energy	Qualified Pension Benefit		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2022	2021	2022	2021	2022	2021
Other changes (pre-tax) in plan assets and benefit obligations recognized in other comprehensive income:						
Net loss (gain)	$ 12,736	$ (61,345)	$ (5,260)	$ 828	$ (1,468)	$ (1,164)
Amortization of net (loss) gain	(15,080)	(21,862)	(2,648)	(2,343)	35	53
Settlements, mergers, sales, and closures	—	—	(331)	(886)	—	—
Prior service cost (credit)	—	—	—	—	38	205
Amortization of prior service (cost) credit	—	1,513	(289)	(349)	(22)	(6)
Total change in other comprehensive income for year	$ (2,344)	$ (81,694)	$ (8,528)	$ (2,750)	$ (1,417)	$ (912)

The aggregate expected contributions by the Company to fund the qualified pension plan, SERP and the other postretirement plans for the year ending December 31, 2023, are expected to be at least $18.0 million, $3.5 million and $0.3 million, respectively.

Assumptions

In accounting for pension and other benefit obligations and costs under the plans, the following weighted-average actuarial assumptions were used by the Company:

	Qualified Pension Benefits			SERP Pension Benefits			Other Benefits		
Benefit Obligation Assumptions:	2022	2021	2020	2022	2021	2020	2022	2021	2020
Discount rate	5.60 %	3.00 %	2.70 %	5.60 %	3.00 %	2.70 %	5.60 %	3.00 %	2.70 %
Rate of compensation increase	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50
Interest crediting rate	4.00	4.00	4.00	N/A	N/A	N/A	N/A	N/A	N/A
Benefit Cost Assumptions:									
Discount rate	3.00	2.70	3.35	3.00	2.70	3.35	3.00	2.70	3.35
Return on plan assets	6.50	6.50	7.15	—	—	—	7.00	7.00	7.00
Rate of compensation increase	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50
Interest crediting rate	4.00	4.00	4.00	N/A	N/A	N/A	N/A	N/A	N/A

The Company has selected the expected return on plan assets based on a historical analysis of rates of return and the Company’s investment mix, market conditions, inflation and other factors. The expected rate of return is reviewed annually based on these factors. The Company’s accounting policy for calculating the market-related value of assets for the Company’s retirement plan is based on a five-year smoothing of asset gains (losses) measured from the expected return on market-related assets. This is a calculated value that recognizes changes in fair value in a systematic and rational manner over five years. The same manner of calculating market-related value is used for all classes of assets, and is applied consistently from year to year.

Puget Energy’s pension and other postretirement benefits income or costs depend on several factors and assumptions, including plan design, timing and amount of cash contributions to the plan, earnings on plan assets, discount rate, expected long-term rate of return, and mortality trends. Changes in any of these factors or assumptions will affect the amount of income or expense that Puget Energy records in its financial statements in future years and its projected benefit obligation. Puget Energy has selected an expected return on plan assets based on a historical analysis of rates of return and Puget Energy’s investment mix, market conditions, inflation and other factors. As required by merger accounting rules, market-related value was reset to market value effective with the merger.

The discount rates were determined by using market interest rate data and the weighted-average discount rate from the FTSE Pension Discount Curve (formerly known as the Citigroup Pension Liability Index Curve). The Company also takes into account in determining the discount rate the expected changes in market interest rates and anticipated changes in the duration of the plan liabilities. The Company's projected benefit obligation for pension plans experienced an actuarial gain of $215.0 million in 2022. This is primarily due to the increase in the discount rate used in measuring the benefit obligation.

Plan Benefits

The expected total benefits to be paid during the next five years and the aggregate total to be paid for the five years thereafter are as follows:

(Dollars in Thousands)	2023	2024	2025	2026	2027	2028-2032
Qualified Pension total benefits	$ 46,500	$ 47,800	$ 48,700	$ 49,900	$ 50,700	$ 260,700
SERP Pension total benefits	3,532	1,844	7,634	2,271	10,956	7,479
Other Benefits total	912	890	881	879	854	3,829

Plan Assets

Plan contributions and the actuarial present value of accumulated plan benefits are prepared based on certain assumptions pertaining to interest rates, inflation rates and employee demographics, all of which are subject to change. Due to uncertainties inherent in the estimations and assumptions process, changes in these estimates and assumptions in the near term may be material to the financial statements.

The Company has a Retirement Plan Committee that establishes investment policies, objectives and strategies designed to balance expected return with a prudent level of risk. All changes to the investment policies are reviewed and approved by the Retirement Plan Committee prior to being implemented.

The Retirement Plan Committee invests trust assets with investment managers who have historically achieved above-median long-term investment performance within the risk and asset allocation limits that have been established. Interim evaluations are routinely performed with the assistance of an outside investment consultant.

To obtain the desired return needed to fund the pension benefit plans, the Retirement Plan Committee has established investment allocation percentages by asset classes as follows:

	Allocation		
Asset Class	Minimum	Target	Maximum
Domestic large cap equity	25 %	31 %	40 %
Domestic small cap equity	—	9	15
Non-U.S. equity	10	25	30
Fixed income	25	35	40
Real estate	—	—	10
Cash	—	—	5

Plan Fair Value Measurements

ASC 715, "Compensation – Retirement Benefits" (ASC 715) directs companies to provide additional disclosures about plan assets of a defined benefit pension or other postretirement plan. The objectives of the disclosures are to disclose the following: (i) how investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies; (ii) major categories of plan assets; (iii) inputs and valuation techniques used to measure the fair value of plan assets; (iv) effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period; and (v) significant concentrations of risk within plan assets.

ASC 820 allows the reporting entity, as a practical expedient, to measure the fair value of investments that do not have readily determinable fair values on the basis of the net asset value per share of the investment if the net asset value of the investment is calculated in a matter consistent with ASC 946, "Financial Services – Investment Companies". The standard requires disclosures about the nature and risk of the investments and whether the investments are probable of being sold at amounts different from the net asset value per share.

The following table sets forth by level, within the fair value hierarchy, the qualified pension plan as of December 31, 2022, and 2021:

	Recurring Fair Value Measures				Recurring Fair Value Measures			
	December 31, 2022				December 31, 2021			
(Dollars in Thousands)	Level 1	Level 2	Other	Total	Level 1	Level 2	Other	Total
Assets:								
Common Stock:								
Domestic	$ 175,969	$ 298	$ —	$ 176,267	$ 249,021	$ 99	$ —	$ 249,120
Foreign	17,767	—	—	17,767	25,963	—	—	25,963
Government Securities	61,693	8,828	—	70,521	65,266	2,470	—	67,736
Corporate Securities:								
Domestic	—	16,005	—	16,005	—	12,820	—	12,820
Foreign	—	6,525	—	6,525	—	5,239	—	5,239
Cash and cash equivalents	4,678	(632)	—	4,046	3,638	(540)	—	3,098
Investments measured at NAV:								

Collective Investment Funds	—	—	262,910	262,910	—	—	359,861	359,861
Partnership	—	—	86,827	86,827	—	—	115,570	115,570
Mutual Funds	—	—	46,005	46,005	—	—	80,724	80,724
Other	—	—	846	846	—	—	1,434	1,434
Net (payable) receivable	—	—	(29,186)	(29,186)	—	—	(23,015)	(23,015)
Total assets	$ 260,107	$ 31,024	$ 367,402	$ 658,533	$ 343,888	$ 20,088	$ 534,574	$ 898,550

The following table sets forth by level, within the fair value hierarchy, the Other Benefits plan assets which consist of insurance benefits for retired employees, at fair value:

	Recurring Fair Value Measures December 31, 2022				Recurring Fair Value Measures December 31, 2021			
(Dollars in Thousands)	Level 1	Level 2	Other	Total	Level 1	Level 2	Other	Total
Assets:								
Money Markets	$ —	$ —	$ —	$ —	$ 4	$ —	$ —	$
Mutual fund	—	5,190	—	5,190	—	6,337	—	6,33
Net (payable) receivable	—	—	—	—	—	—	—	–
Total assets	$ —	$ 5,190	$ —	$ 5,190	$ 4	$ 6,337	$ —	$ 6,34

The following discussion provides information regarding the methods used in valuation of the various asset class investments held for the pension and other postretirement benefit plans.

- Mutual funds classified as Level 1 securities have pricing inputs that are based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and New York Stock Exchange (NYSE). Mutual fund assets not included in the fair value hierarchy are privately held funds. These funds are not actively traded and utilize net asset value (NAV) as a practical expedient to measure fair value.
- Common stock investments are traded in active markets on national and international securities exchanges and are valued at closing prices on the last business day of each period presented. They are classified as Level 1 securities.
- Corporate and some government debt securities are valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings. Some government debt securities have quoted prices such as certain treasury securities and are classified as Level 1 securities.

- Cash and cash equivalents comprise mostly of money market funds and foreign currency held. Money market funds are classified as Level 1 instruments as pricing inputs are based on unadjusted prices in an active market while foreign currency held is classified as a Level 2 investment based on inputs that are indirectly observable.
- Investments in collective trust funds and partnerships are stated at the NAV as determined by the issuer of fund and are based on the fair value of the underlying investments held by the fund less its liabilities. The NAV is used as a practical expedient to estimate fair value. These funds are primarily invested in a blend of corporate and government debt securities as well as international equities.

(14) Income Taxes

The details of income tax (benefit) expense are as follows:

Puget Energy	Year Ended December 31,		
(Dollars in Thousands)	2022	2021	2020
Charged to operating expenses:			
Current:			
Federal	$ 41,198	$ 25,395	$ 7,962
State	628	721	7
Deferred:			
Federal	17,866	(1,759)	(6,414)
State	6	158	109
Total income tax expense	$ 59,698	$ 24,515	$ 1,664

Puget Sound Energy	Year Ended December 31,		
(Dollars in Thousands)	2022	2021	2020
Charged to operating expenses:			

Current:						
Federal	$	81,597	$	52,616	$	10,607
State		869		670		383
Deferred:						
Federal		(2,171)		(9,027)		15,252
State		—		—		—
Total income tax expense	$	80,295	$	44,259	$	26,242

The following reconciliation compares pre-tax book income at the federal statutory rate of 21.0% to the actual income tax expense in the Statements of Income:

Puget Energy	Year Ended December 31,					
(Dollars in Thousands)	2022		2021		2020	
Income taxes at the statutory rate	$	99,549	$	59,927	$	38,720
Increase (decrease):						
Utility plant differences[1]	$	(23,028)	$	(22,325)	$	(22,991)
AFUDC, net		(3,567)		1,509		(6,095)
Executive compensation		1,821		1,386		2,440
Treasury grant amortization		(5,717)		(5,424)		(8,935)
Excess deferred tax amortization		(13,722)		(13,392)		(3,038)
Other–net		4,362		2,834		1,563
Total income tax expense	$	59,698	$	24,515	$	1,664
Effective tax rate		12.6 %		8.6 %		0.9 %

Puget Sound Energy	Year Ended December 31,					
(Dollars in Thousands)	2022		2021		2020	
Income taxes at the statutory rate	$	119,962	$	79,868	$	63,110
Increase (decrease):						
Utility plant differences[1]	$	(23,028)	$	(22,325)	$	(22,991)
AFUDC, net		(3,567)		1,509		(6,095)
Executive compensation		1,821		1,386		2,440
Treasury grant amortization		(5,717)		(5,424)		(8,935)
Excess deferred tax amortization		(13,722)		(13,392)		(3,038)
Other–net		4,546		2,637		1,751
Total income tax expense	$	80,295	$	44,259	$	26,242
Effective tax rate		14.1 %		11.6 %		8.7 %

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1. *Utility plant differences include the reversal of excess deferred taxes using the average rate assumption method in the amount of $27.2 million and $27.6 million in 2022 and 2021, respectively.*

The Company's net deferred tax liability at December 31, 2022, and 2021, is composed of amounts related to the following types of temporary differences:

Puget Energy	At December 31,			
(Dollars in Thousands)	2022		2021	
Utility plant and equipment	$	1,853,450	$	1,892,692
Unrealized gain on derivative instruments		158,175		50,971
Other deferred tax liabilities		365,035		313,270
Subtotal deferred tax liabilities		2,376,660		2,256,933
Net operating loss carryforward		(234,825)		(254,007)

Net regulatory liability for income taxes	(811,161)	(865,976)
Other deferred tax assets	(299,597)	(184,023)
Unrealized loss on derivative instruments	(45,130)	(40,443)
Subtotal deferred tax assets	(1,390,713)	(1,344,449)
Total net deferred tax liabilities	$ 985,947	$ 912,484

Puget Sound Energy	At December 31,	
(Dollars in Thousands)	2022	2021
Utility plant and equipment	$ 1,852,644	$ 1,892,674
Unrealized gain on derivative instruments	143,147	31,940
Other deferred tax liabilities	279,612	225,753
Subtotal deferred tax liabilities	2,275,403	2,150,367
Net regulatory liability for income taxes	(811,724)	(866,541)
Other deferred tax assets	(293,977)	(178,211)
Unrealized loss on derivative instruments	(30,102)	(21,412)
Subtotal deferred tax assets	(1,135,803)	(1,066,164)
Total net deferred tax liabilities	$ 1,139,600	$ 1,084,203

The Company calculates its deferred tax assets and liabilities under ASC 740, “Income Taxes” (ASC 740). ASC 740 requires recording deferred tax balances, at the currently enacted tax rate, on assets and liabilities that are reported differently for income tax purposes than for financial reporting purposes. The utilization of deferred tax assets requires sufficient taxable income in future years. ASC 740 requires a valuation allowance on deferred tax assets when it is more likely than not that the deferred tax assets will not be realized. PSE fully utilized its PTC balance in 2021 and had no carryforwards at the end of 2021. Puget Energy’s net operating loss carryforwards expire from 2029 through 2037. Net operating losses generated in 2018 and thereafter have no expiration date. No valuation allowance has been provided for net operating loss carryforwards.

Unrecognized Tax Benefits

The Company accounts for uncertain tax positions under ASC 740, which clarifies the accounting for uncertainty in income taxes recognized in the financial statements. ASC 740 requires the use of a two-step approach for recognizing and measuring tax positions taken or expected to be taken in a tax return. First, a tax position should only be recognized when it is more likely than not, based on technical merits, that the position will be sustained upon challenge by the taxing authorities and taken by management to the court of last resort. Second, a tax position that meets the recognition threshold should be measured at the largest amount that has a greater than 50.0% likelihood of being sustained.

As of December 31, 2022, and 2021, the Company had no material unrecognized tax benefits. As a result, no interest or penalties were accrued for unrecognized tax benefits during the year.

The Company has open tax years from 2019 through 2022. The Company classifies interest as interest expense and penalties as other expense in the financial statements.

(15) Litigation

From time to time, the Company is involved in litigation or legislative rulemaking proceedings relating to its operations in the normal course of business. The following is a description of pending proceedings that are material to PSE’s operations:

Colstrip

PSE has a 50% ownership interest in Colstrip Units 1 and 2 and a 25% interest in each of Colstrip Units 3 and 4, which are coal-fired generating units located in Colstrip, Montana. PSE has accelerated the depreciation of Colstrip Units 3 and 4 to December 31, 2025 as part of the 2019 GRC. The 2017 GRC repurposed PTCs and hydro-related treasury grants to recover unrecovered plant costs and to fund and recover decommissioning and remediation costs for Colstrip Units 1 through 4. On September 2, 2022, PSE and Talen Energy reached an agreement to transfer PSE's ownership interest in Colstrip Units 3 and 4 to Talen Energy on December 31, 2025. Management evaluated Colstrip Units 3 and 4 and determined that the applicable held for sale accounting criteria were not met as of December 31, 2022. As such, Colstrip Units 3 and 4 are classified as Electric Utility Plant on the Company's balance sheet as of December 31, 2022.

Consistent with a June 2019 announcement, Talen permanently shut down Units 1 and 2 at the end of 2019 due to operational losses associated with the Units. Colstrip Units 1 and 2 were retired effective December 31, 2019. The Washington Clean Energy Transformation Act requires the Washington Commission to provide recovery of the investment, decommissioning, and remediation costs associated with the facilities that are not recovered through the repurposed PTCs and hydro-related treasury grants. The full scope of decommissioning activities and costs may vary from the estimates that are available at this time.

On May 19, 2021, PSE along with the Colstrip owners, Avista Corporation, PacifiCorp and Portland General Electric Company filed a lawsuit against the Montana Attorney General challenging the constitutionality of Montana Senate Bill 266. On October 13, 2021, the United States District Court for the District of Montana issued a preliminary injunction finding it likely that Senate Bill 266 unconstitutionally violates the Commerce Clause and Contract Clause of the United States Constitution. Since then, a motion for summary judgment was filed requesting a permanent injunction against enforcement of Senate Bill 266. On September 29, 2022, the magistrate judge in the District Court proceeding issued a recommendation to the presiding U.S. District Court Judge that a permanent injunction against enforcement of Senate Bill 266 be granted. On October 18, 2022, the U.S. District Court Judge accepted in full the magistrate judge recommendation for a permanent injunction against enforcement of Senate Bill 266.

Puget LNG

In January 2018, the Puget Sound Clean Air Agency (PSCAA) determined a Supplemental Environmental Impact Statement (SEIS) was necessary in order to rule on the air quality permit for the facility. In December 2019, PSCAA issued the air quality permit for the facility, a decision which was appealed to the Washington Pollution Control Hearings Board (PCHB) by each of the Puyallup Tribe of Indians and nonprofit law firm Earthjustice. In November 2021, the PCHB affirmed the PSCAA ruling in PSE's favor. In December 2021, the PCHB decision was appealed with the Pierce County Superior Court by each of the Puyallup Tribe of Indians and nonprofit law firm Earthjustice. The appeal did not delay commissioning or commercial operations at the plant, which commenced on February 1, 2022.

(16) Commitments and Contingencies

For the year ended December 31, 2022, approximately 16.4% of the Company’s energy output was obtained at an average cost of approximately $0.034 per Kilowatt Hour (kWh) through long-term contracts with three of the Washington Public Utility Districts (PUDs) that own hydroelectric projects on the Columbia River. The purchase of power from the Columbia River projects is on a pro rata share basis under which the Company pays a proportionate share of the annual debt service, operating and maintenance costs and other expenses associated with each project, in proportion to the contractual share of power that PSE obtains from that project. In these instances, PSE’s payments are not contingent upon the projects being operable; therefore, PSE is required to make the payments even if power is not delivered. These projects are financed substantially through debt service payments and their annual costs should not vary significantly over the term of the contracts unless additional financing is required to meet the costs of major maintenance, repairs or replacements, or license requirements. The Company’s share of the costs and the output of the projects is subject to reduction due to various withdrawal rights of the PUDs and others over the contract lives.

The Company's expenses under these PUD contracts were as follows for the years ended December 31:

(Dollars in Thousands)	2022	2021	2020
PUD contract costs	$ 149,575	$ 117,812	$ 116,874

As of December 31, 2022, the Company purchased portions of the power output of the PUDs' projects as set forth in the following table:

		Company's Share of					
(Dollars in Thousands)	Contract Expiration	2023 Percent of Output	2023 Megawatt Capacity	Estimated 2023 Total Costs	2023 Debt Service Costs	Interest included in 2023 Debt Service Costs	Debt Outstanding
Chelan County PUD[1]:							
Rock Island Project	2031	30.0 %	187	$ 47,892	$ 12,072	$ 5,132	$ 93,493
Rocky Reach Project	2031	30.0	390	54,022	5,039	1,907	33,757
Douglas County PUD[2]:							
Wells Project	2028	32.8	276	45,489	—	—	—
Grant County PUD[3]:							
Priest Rapids Development	2052	4.8	45	28,243	747	376	9,768
Wanapum Development	2052	4.8	58	28,243	747	376	9,768
Total			956	$ 203,889	$ 18,605	$ 7,791	$ 146,786

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1. *In March 2021, PSE entered into a new PPA with Chelan County PUD for additional Rocky Reach and Rock Island output. The contract began on January 1, 2022, and continues through December 31, 2026. This agreement increases PSE’s share of output by 5% for each project, which equates to an additional capacity of 31MW for Rock Island and 65MW for Rocky Reach.*

2. *In March 2021, PSE entered into a new agreement with Douglas County PUD for the extension of the Wells Project Output that began on October 1, 2021, and continues through September 30, 2024. This agreement increases PSE's share of output by 5.5% for the Wells Project, which equates to an additional capacity of 46MW.*

3. *In November 2022, PSE elected to take its portion of the Priest Rapid Meaningful Priority and was granted 4.13% share of the 2023 Priest Rapids Project output. This one-year contract begins on January 1, 2023, and continues through December 31, 2023. This agreement increases PSE's share of output by 4.13%, which equates to an additional capacity of 39MW for Priest Rapids Development and 51 MW for Wanapum Development.*

The following table summarizes the Company's estimated payment obligations for power purchases from the Columbia River projects, electric portfolio contracts and electric wholesale market transactions. These contracts have varying terms and may include escalation and termination provisions.

(Dollars in Thousands)	2023	2024	2025	2026	2027	Thereafter	Total
Columbia River projects	$ 191,618	$ 145,078	$ 140,887	$ 138,482	$ 123,152	$ 394,875	$ 1,134,092
Electric portfolio contracts	380,559	385,807	345,257	142,273	133,903	1,776,703	3,164,502
Electric wholesale market transactions	414,278	148,628	11,616	11,616	—	—	586,138
Total	$ 986,455	$ 679,513	$ 497,760	$ 292,371	$ 257,055	$ 2,171,578	$ 4,884,732

Total purchased power contracts provided the Company with approximately 15.3 million, 13.1 million and 13.2 million MWhs of firm energy at a cost of approximately $892.7 million, $631.4 million and $491.7 million for the years 2022, 2021, and 2020, respectively.

Natural Gas Supply Obligations

The Company has entered into various firm supply, transportation and storage service contracts in order to ensure adequate availability of natural gas supply for its customers and generation requirements. The Company contracts for its long-term natural gas supply on a firm basis, which means the Company has a 100% daily take obligation and the supplier has a 100% daily delivery obligation to ensure service to PSE's customers and generation requirements. The transportation and storage contracts, which have remaining terms from 1 year to 22 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage.

The Company incurred demand charges of $138.3 million, $136.4 million, and $135.8 million for firm transportation, storage and peaking services for its natural gas customers for the years 2022, 2021, and 2020. The Company incurred demand charges of $53.9 million, $52.8 million, and $51.2 million for firm transportation, storage and peaking services for the natural gas supply for its combustion turbines for the years 2022, 2021, and 2020.

The following table summarizes the Company's obligations for future natural gas supply and demand charges through the primary terms of its existing contracts. The quantified obligations are based on the FERC and CER (Canadian Energy Regulator) currently authorized rates, which are subject to change.

Natural Gas Supply and Demand Charge Obligations (Dollars in Thousands)	2023	2024	2025	2026	2027	Thereafter	Total
Natural gas wholesale market transactions	$ 1,013,547	$ 377,588	$ 351,129	$ 255,577	$ 76,453	$ —	$ 2,074,294
Firm transportation service	175,136	146,675	112,327	94,417	94,123	570,687	1,193,365
Firm storage service	9,350	7,923	7,448	7,432	7,352	1,838	41,343
Total	$ 1,198,033	$ 532,186	$ 470,904	$ 357,426	$ 177,928	$ 572,525	$ 3,309,002

Service Contracts

The following table summarizes the Company's estimated obligations for service contracts through the terms of its existing contracts.

Service Contract Obligations (Dollars in Thousands)	2023	2024	2025	2026	2027	Thereafter	Total
Energy production service contracts	$ 33,971	$ 34,812	$ 35,772	$ 18,728	$ 19,221	$ 79,655	$ 222,159
Automated meter reading system	50,124	47,301	47,668	48,803	—	—	193,896
Total	$ 84,095	$ 82,113	$ 83,440	$ 67,531	$ 19,221	$ 79,655	$ 416,055

Chelan PUD Power Purchase Agreement

On February 7, 2023, PSE and Chelan PUD entered into a new power purchase agreement, under which PSE will continue to purchase 25% of the total output from the Rocky Reach and Rock Island hydroelectric projects from November 1, 2031 through October 31, 2051. Estimated payment obligations under the new power sales agreement total $3.1 billion.

Other Commitments and Contingencies

For information regarding PSE's environmental remediation obligations, see Note 4, "Regulation and Rates," to the consolidated financial statements included in Item 8 of this report.

(17) Related Party Transactions

The Company identified no material related party transactions during the year ended December 31, 2022 and December 31, 2021.

(18) Segment Information

Puget Energy and PSE operate one reportable segment referred to as the regulated utility segment. Puget Energy's regulated utility operation generates, purchases and sells electricity and purchases, transports and sells natural gas. The service territory of PSE covers approximately 6,000 square miles in the state of Washington.

(19) Accumulated Other Comprehensive Income (Loss)

The following tables present the changes in the Company's (loss) AOCI by component for the years ended December 31, 2022, 2021, and 2020, respectively:

Puget Energy Changes in AOCI, net of tax (Dollars in Thousands)	Net unrealized gain (loss) and prior service cost on pension plans	Total
Balance at December 31, 2019	$ (84,149)	$ (84,149)
Other comprehensive income (loss) before reclassifications	(9,058)	(9,058)
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	6,770	6,770
Net current-period other comprehensive income (loss)	(2,288)	(2,288)
Balance at December 31, 2020	$ (86,437)	$ (86,437)
Other comprehensive income (loss) before reclassifications	49,226	49,226
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	9,779	9,779
Net current-period other comprehensive income (loss)	59,005	59,005
Balance at December 31, 2021	$ (27,432)	$ (27,432)
Other comprehensive income (loss) before reclassifications	(4,559)	(4,559)
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	7,217	7,217
Net current-period other comprehensive income (loss)	2,658	2,658
Balance at December 31, 2022	$ (24,774)	$ (24,774)

Puget Sound Energy Changes in AOCI, net of tax (Dollars in Thousands)	Net unrealized gain (loss) and prior service cost on pension plans	Net unrealized gain (loss) on treasury interest rate swaps	Total
Balance at December 31, 2019	$ (183,108)	$ (5,369)	$ (188,477)
Other comprehensive income (loss) before reclassifications	(8,717)	—	(8,717)
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	15,853	385	16,238
Net current-period other comprehensive income (loss)	7,136	385	7,521
Balance at December 31, 2020	$ (175,972)	$ (4,984)	$ (180,956)
Other comprehensive income (loss) before reclassifications	49,265	—	49,265
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	18,166	384	18,550
Net current-period other comprehensive income (loss)	67,431	384	67,815
Balance at December 31, 2021	$ (108,541)	$ (4,600)	$ (113,141)
Other comprehensive income (loss) before reclassifications	(4,512)	—	(4,512)
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	14,223	386	14,609
Net current-period other comprehensive income (loss)	9,711	386	10,097
Balance at December 31, 2022	$ (98,830)	$ (4,214)	$ (103,044)

Details about the reclassifications out of AOCI (loss) for the years ended December 31, 2022, 2021, and 2020, respectively, are as follows:

Puget Energy

(Dollars in Thousands)

Details about accumulated other comprehensive income (loss) components	Affected line item in the statement where net income (loss) is presented	Amount reclassified from accumulated other comprehensive income (loss)		
		2022	2021	2020
Net unrealized gain (loss) and prior service cost on pension plans:				
Amortization of prior service cost	(a)	$ (311)	$ 1,549	$ 1,631
Amortization of net gain (loss)	(a)	(8,824)	(13,928)	(10,200)
	Total before tax	(9,135)	(12,379)	(8,569)
	Tax (expense) or benefit	1,918	2,600	1,799
	Net of tax	(7,217)	(9,779)	(6,770)
Total reclassification for the period	Net of tax	$ (7,217)	$ (9,779)	$ (6,770)

[(a)] *These AOCI components are included in the computation of net periodic pension cost, see Note 13, "Retirement Benefits," to the consolidated financial statements included in Item 8 of this report for additional details.*

Puget Sound Energy

(Dollars in Thousands)

Details about accumulated other comprehensive income (loss) components	Affected line item in the statement where net income (loss) is presented	Amount reclassified from accumulated other comprehensive income (loss)		
		2022	2021	2020
Net unrealized gain (loss) and prior service cost on pension plans:				
Amortization of prior service cost	(a)	$ (311)	$ 1,158	$ 1,224
Amortization of net gain (loss)	(a)	(17,693)	(24,153)	(21,291)
	Total before tax	(18,004)	(22,995)	(20,067)
	Tax (expense) or benefit	3,781	4,829	4,214
	Net of tax	(14,223)	(18,166)	(15,853)
Net unrealized gain (loss) on treasury interest rate swaps:				
Interest rate contracts	Interest expense	(488)	(487)	(487)
	Tax (expense) or benefit	102	103	102
	Net of tax	(386)	(384)	(385)
Total reclassification for the period	Net of tax	$ (14,609)	$ (18,550)	$ (16,238)

[(a)] *These AOCI components are included in the computation of net periodic pension cost, see Note 13, "Retirement Benefits," to the consolidated financial statements included in item 8 of this report for additional details.*

SCHEDULE I: CONDENSED FINANCIAL INFORMATION OF PUGET ENERGY

Puget Energy

Condensed Statements of Income and Comprehensive Income (Loss)

(Dollars in Thousands)

Year Ended December 31,

	2022	2021	2020
Non-utility expense and other	$ (1,206)	$ (913)	$ (1,579)
Other income (deductions):			
Equity in earnings of subsidiary	474,873	337,405	277,654
Interest income	8,458	4,261	4,760
Interest expense	(84,051)	(100,002)	(123,592)
Income tax benefit (expense)	16,271	20,098	25,474
Net income (loss)	$ 414,345	$ 260,849	$ 182,717
Comprehensive income (loss)	$ 417,003	$ 319,854	$ 180,429

See accompanying notes to the condensed financial statements.

Puget Energy

Condensed Balance Sheets

(Dollars in Thousands)

	December 31,	
	2022	2021
Assets:		
Investment in subsidiaries	$ 4,938,998	$ 4,446,758
Other property and investments:		
Goodwill	1,656,513	1,656,513
Current assets:		
Cash	1,528	6,386
Receivables from affiliates[1]	246,317	233,258
Income tax receivables	532	6,006
Total current assets	248,377	245,650
Long-term assets:		
Deferred income taxes	231,976	250,820
Other	3,370	984
Total long-term assets	235,346	251,804

Total assets	$	7,079,234	$	6,600,725
Capitalization and liabilities:				
Common equity	$	4,964,089	$	4,563,316
Long-term debt		2,020,734		1,571,287
Total capitalization		6,984,823		6,134,603
Current liabilities:				
Accounts payable to affiliates[1]		133		147
Short-term debt		84,300		—
Current maturities of long-term debt		—		450,000
Interest		9,978		15,975
Total current liabilities		94,411		466,122
Commitments and contingencies (Note 16)				
Total capitalization and liabilities	$	7,079,234	$	6,600,725

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[1] *Eliminated in consolidation.*

See accompanying notes to the condensed financial statements.

Puget Energy

Condensed Statements of Cash Flows

(Dollars in Thousands)

	Year Ended December 31,					
		2022		2021		2020
Operating activities:						
Net cash provided by (used in) operating activities	$	(10,197)	$	143,691	$	38,280
Investing activities:						
Investment in subsidiaries		(50,000)		(21,783)		—
(Increase) decrease in loan to subsidiary		(12,176)		—		(31,043)
Net cash provided by (used in) investing activities		(62,176)		(21,783)		(31,043)
Financing activities:						
Dividends paid		(16,230)		(106,420)		(45,421)
Investment from Parent		—		210,000		4,575
Change in short-term debts, net		84,300		—		—
Issuance of long-term debts		448,075		515,475		644,690
Redemption of long-term debts		(450,000)		(734,000)		(609,400)
Issue costs and others		1,370		(1,367)		(1,838)
Net cash provided by (used in) by financing activities		67,515		(116,312)		(7,394)
Increase (decrease) in cash		(4,858)		5,596		(157)
Cash at beginning of year		6,386		790		947

Cash at end of year	$	1,528	$	1,386	$	790

See accompanying notes to the condensed financial statements.

NOTES TO CONDENSED FINANCIAL STATEMENTS

(1) Basis of Presentation

Puget Energy is an energy services holding company that conducts substantially all of its business operations through its regulated subsidiary, PSE. Puget Energy also has a wholly-owned non-regulated subsidiary, named Puget LNG, LLC (Puget LNG). Puget LNG was formed in November 2016, and has the sole purpose of owning, developing and financing the non-regulated activity of a liquefied natural gas (LNG) facility at the Port of Tacoma, Washington. These condensed financial statements and related footnotes have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X. These financial statements, in which Puget Energy's subsidiaries have been included using the equity method, should be read in conjunction with the consolidated financial statements and notes thereto of Puget Energy included in Item 8, "Financial Statements and Supplementary Data" of this report. Puget Energy owns 100% of the common stock of its subsidiaries.

Equity earnings of subsidiary included earnings from PSE and PLNG of $473.8 million, $335.0 million and $274.3 million for the years ended December 31, 2022, 2021, and 2020, respectively, and business combination accounting adjustments under ASC 805 recorded at Puget Energy for PSE of $1.0 million, $2.4 million and $3.4 million for the years ended December 31, 2022, 2021, and 2020, respectively. Investment in subsidiaries includes Puget Energy business combination accounting adjustments under ASC 805 that are recorded at Puget Energy.

(2) Long-Term Debt

For information concerning Puget Energy's long-term debt obligations, see Note 7, "Long-Term Debt" to the consolidated financial statements included in Item 8 of this report.

(3) Commitments and Contingencies

For information concerning Puget Energy's material contingencies and guarantees, see Note 16, "Commitments and Contingencies" to the consolidated financial statements included in Item 8 of this report.

SCHEDULE II: VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Puget Energy and	Balance at	Additions Charged to	Balance

Puget Sound Energy (Dollars in Thousands)	Beginning of Period	Costs and Expenses	Deductions	at End of Period
Year Ended December 31, 2022				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 34,958	$ 28,316	$ 21,312	$ 41,962
Year Ended December 31, 2021				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 20,080	$ 27,204	$ 12,326	$ 34,958
Year Ended December 31, 2020				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 8,294	$ 23,292	$ 11,506	$ 20,080

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Puget Energy

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of Puget Energy's management, including the President and Chief Executive Officer and Senior Vice President and Chief Financial Officer, Puget Energy has evaluated the effectiveness of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934) as of December 31, 2022, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and Senior Vice President and Chief Financial Officer of Puget Energy concluded that these disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There have been no changes in Puget Energy's internal control over financial reporting during the quarter ended December 31, 2022, that have materially affected, or are reasonably likely to materially affect, Puget Energy's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Puget Energy's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Under the supervision and with the participation of Puget Energy's President and Chief Executive Officer and Senior Vice President and Chief Financial Officer, Puget Energy's management assessed the effectiveness of internal control over financial reporting based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, Puget Energy's management concluded that its internal control over financial reporting was effective as of December 31, 2022.

Puget Energy's effectiveness of internal control over financial reporting as of December 31, 2022, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Puget Sound Energy

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of PSE's management, including the President and Chief Executive Officer and Senior Vice President and Chief Financial Officer, PSE has evaluated the effectiveness of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934) as of December 31, 2022, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and Senior Vice President and Chief Financial Officer of PSE concluded that these disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There have been no changes in PSE's internal control over financial reporting during the quarter ended December 31, 2022, that have materially affected, or are reasonably likely to materially affect, PSE's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

PSE's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Under the supervision and with the participation of PSE's President and Chief Executive Officer and Senior Vice President and Chief Financial Officer, PSE's management assessed the effectiveness of internal control over financial reporting based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, PSE's management concluded that its internal control over financial reporting was effective as of December 31, 2022.

PSE's effectiveness of internal control over financial reporting as of December 31, 2022, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Board of Directors

As of February 23, 2023, twelve directors constitute Puget Energy's Board of Directors and thirteen directors currently constitute PSE's Board of Directors, as set forth below. The directors are selected in accordance with the Amended and Restated Bylaws of each of Puget Energy and PSE, pursuant to which, the investor-owners of Puget Holdings (the indirect parent company of both Puget Energy and PSE) are entitled to select individuals to serve on the boards of Puget Energy and PSE.

Scott Armstrong, age 63, has been a director on the boards of PSE since June of 2015 and on the board of Puget Energy since November 2017. Mr. Armstrong previously served as Chief Executive Officer of Concure Oncology from March 2020 to November 2021. Prior to that Mr. Armstrong was President and CEO of Group Health Cooperative of Seattle, Washington, a health insurance and medical care provider, positions he had held since January 2005, until its acquisition by Kaiser Permanente on February 1, 2017. An independent director not affiliated with any of the Company's investors, Mr. Armstrong's executive leadership experience in a heavily regulated industry that has undergone extensive change, along with his involvement in civic affairs in the Pacific Northwest, are among the reasons for his appointment to the Puget Energy and PSE boards.

Richard Dinneny, age 60, has been a director on the boards of both Puget Energy and PSE since April 17, 2019. Mr. Dinneny previously served as Senior Portfolio Manager, Infrastructure and Renewable Resources for British Columbia Investment Management Corporation (BCI) where he had the responsibility for all aspects of investing in infrastructure transactions from 2015 to May 31, 2021. Mr. Dinneny serves on the boards of Puget Energy and PSE as a representative of BCI's ownership interests, pursuant to the terms of the Puget Energy and PSE bylaws.

Barbara Gordon, age 64, has been a director on the board of PSE since November 2017 and on the board of Puget Energy since August 2022. Ms. Gordon previously served as a Vice President of the board of directors for Seattle-King County Habitat for Humanity, a non-profit organization (2016-2018). Prior to that time, Ms. Gordon served as Executive Vice President and Chief Customer Officer of Bellevue-based Apptio, a developer of technology business management software (2016-2017), Senior Vice President and Chief Operating Officer of Isilon/EMC, a digital storage systems company (2013-2016), and as Corporate Vice President of Worldwide Customer Service and Support at Microsoft (2003-2013). An independent director not affiliated with any of the Company's investors, Ms. Gordon brings to the Board her expertise in customer-facing technology initiatives and enterprise level management of customer service and support.

Chris Parker, age 52, has been a director of both Puget Energy and PSE since February 22, 2022. Mr. Parker is currently a member of the Ontario Teachers' Pension Plan North America Infrastructure team where he focuses on origination, execution and management of infrastructure investments. He joined Ontario Teachers' Pension Plan in 2011 and has served on the board of directors of Northern Star Generation, Intergen, Express Pipeline, Ontario Teachers' New Zealand Forest Investments and Sydney Desalination Plant. He currently serves on the board of directors of Chicago Skyway. Prior to joining Ontario Teachers', Chris worked on power and utility investments at Brookfield Asset Management. Mr. Parker was selected by Clean Energy JV Sub 2, LP and pursuant to the Amended and Restated Bylaws of each of the Companies, will serve as an Owner

Director on their respective Boards of Directors. Mr. Parker will not receive any director compensation from the Companies for his service as an Owner Director on the Boards, but will be reimbursed for out-of-pocket expenses.

Grant Hodgkins, age 47, has been a director on the boards of both Puget Energy and PSE since December 31, 2020. Mr. Hodgkins is currently the Portfolio Manager, Infrastructure and Renewable Resources Group, for British Columbia Investment Management Corporation (BCI), which position he has held since September 2017, where he has responsibility for all aspects of investing in infrastructure transactions. Mr. Hodgkins is a director of Corix Infrastructure Inc., a water and wastewater utility and contract energy company based in Vancouver, British Columbia. Mr. Hodgkins was selected by BCI and pursuant to the Amended and Restated Bylaws of each of the Companies, will serve as an Owner Director on their respective Boards of Directors. Mr. Hodgkins will not receive any director compensation from the Companies for his service as an Owner Director on the Boards, but will be reimbursed for out-of-pocket expenses.

Tom King, age 61, has been a director on the boards of both Puget Energy and PSE since April 17, 2019. Mr. King is currently the Interim CEO of Woodway Energy Infrastructure, an Intra State Pipeline, which position he has held since December 2022. He is also an Operating Executive with AEA investors, a middle market private equity firm, which position he has held since 2017. Mr. King served as Chairman and President of National Grid U.S. from 2007-2015. Prior to that, he was president of PG&E Corporation and Chairman and CEO of Pacific Gas and Electric from 2003-2007. Mr. King serves on the board of Entregado Group and Allied Power Group. Mr. King serves on the boards of Puget Energy and PSE as a joint representative of Macquarie Washington Clean Energy Investment, L.P. and Ontario Teachers' Pension Plan ownership interests, pursuant to the terms of the Puget Energy and PSE bylaws. Mr. King's experience as an executive officer of regulated utilities and his extensive familiarity with managing operational change are among the reasons for his continuing service as a member of the Puget Energy and PSE boards.

Mary Kipp, age 55, has been a director on the boards of both Puget Energy and PSE since January 3, 2020. Ms. Kipp has served as President and Chief Executive officer since January 3, 2020, and was President of Puget Energy and PSE from August 2019 to December 2019. Prior to that time Ms. Kipp served as President, Chief Executive Officer and Director of El Paso Electric Company (El Paso) from May 2017 to August 2019. Ms. Kipp also serves on the board of Hawaiian Electric Industries, Inc., owner of a provider of electric utility services in Hawaii, and Boston Properties, Inc., a publicly traded developer, owner and manager of Class A office properties.

Jean-Paul Marmoreo, age 47, has been a director on the boards of both Puget Energy and PSE since September 3, 2021. Mr. Marmoreo is currently the Director Asset Management of OMERS Infrastructure Management Inc., since January 2019. He is currently on the boards of Calumet Concession Partners Inc., CannAmm GP Inc., and Commodore US Holding Corporation. Mr. Marmoreo previously served as Director of OMERS Infrastructure Management Inc. from February 2018 to January 2019 and Secretary of Airports Worldwide from April 2017 to August 2018. Mr. Marmoreo was selected by OMERS and pursuant to the Amended and Restated Bylaws of each of the Companies, will serve as an Owner Director on their respective Boards of Directors. Mr. Marmoreo will not receive any director compensation from the Companies for his service as an Owner Director on the Boards, but will be reimbursed for out-of-pocket expenses.

Paul McMillan, age 68, has been a director on the boards of both Puget Energy and PSE since April 23, 2015. Mr. McMillan is currently principal of Tidal Shift Capital Inc. of Toronto, Ontario, Canada, which provides consulting and project development services to energy and infrastructure clients, he has held the position since July 2009. He served as Senior Vice President of EPCOR Energy Division of Edmonton, Alberta, Canada, from May 2005 to July 2009 and President of EPCOR Merchant and Capital LP from September 2000 to May 2005. Mr. McMillan serves on the boards of Puget Energy and PSE as a representative of Aimco's ownership interests, pursuant to the terms of the Puget Energy and PSE bylaws, and brings to this service his experience in energy and gas operations and trading as well as renewable and gas project development.

Diana Birkett Rakow, age 45, has been a director on the board of PSE since May 5, 2022. Ms. Rakow is currently the Senior Vice President of Public Affairs and Sustainability of Alaska Air Group, Inc., since November 2021. She previously served as Vice President of External Relations at Alaska Airlines from September 2017 to February 2021. Ms. Rakow also currently services as the current board chair for the Alaska Airlines Foundation, and serves on the boards of Philanthropy Northwest, the Bay Area Council, and the Pacific Science Center. An independent director not affiliated with any of the Company's investors, Ms. Rakow brings to the Board her expertise in ESG and climate strategy, governance and regulation.

Aaron Rubin, age 45, has been a director on the boards of both Puget Energy and PSE since February 22, 2022. Mr. Rubin is currently responsible for Macquarie Asset Management's Real Assets investment team that focuses on sustainable energy investments in the Americas. Since joining Macquarie in 2008, Mr. Rubin has had responsibility for investment origination and execution and the management of portfolio companies. Mr. Rubin currently serves on the board of directors of Cyrq Energy, Cleco Corporation and Lordstown Energy Center. Mr. Rubin was selected by Clean Energy JV Sub 1, LP and pursuant to the Amended and Restated Bylaws of each of the Companies, will serve as an Owner Director on their respective Boards of Directors. Mr. Rubin will not receive any director compensation from the Companies for his service as an Owner Director on the Boards, but will be reimbursed for out-of-pocket expenses.

Martijn Verwoest, age 46, has been a director on the boards of both Puget Energy and PSE since April 17, 2019. Mr. Verwoest is currently the Head of Energy & Utilities at Stichting Pensioenfonds Zorg en Welzijn (PGGM), and is a member of their Infrastructure Investment Committee since 2007. From 2001 to 2007, he worked in PGGM's public equity department. Mr. Verwoest will not receive any director compensation from the Companies for his service as an Owner Director on the Boards, but will be reimbursed for out-of-pocket expenses.

Steven Zucchet, age 57, has been a director on the boards of both Puget Energy and PSE since April 17, 2019. Mr. Zucchet is currently the Managing Director at Ontario Municipal Employees Retirement System Infrastructure Management (OMERS), which position he has held since January 2019. Since joining OMERS in 2003, Mr. Zucchet has led numerous transactions and had asset management responsibilities at a number of utility and generation companies in Canada and the United States. He is currently on the board of Oncor and Bruce Power Inc. Mr. Zucchet will not receive any director compensation from the Companies for his service as an Owner Director on the Boards, but will be reimbursed for out-of-pocket expenses.

Executive Officers

The information required by this item with respect to Puget Energy and PSE is incorporated herein by reference to the material under "Executive Officers of the Registrants" in Part I of this report.

Audit Committee

The Puget Energy and PSE Boards of Directors have both established an Audit Committee. Directors Richard Dinneny, Paul McMillan, Tom King, Jean-Paul Marmoreo and Diana Rakow are the members of the Audit Committee. The Board has determined that Paul McMillan meets the definition of "Audit Committee Financial Expert" under United States Securities and Exchange Commission (SEC) rules. Puget Energy and PSE currently do not have any outstanding stock listed on a national securities exchange and, therefore, there are no independence standards applicable to either company in connection with the independence of its Audit Committee members.

Procedures by which Shareholders may recommend Nominees to the Board of Directors

There have been no material changes to the procedures by which shareholders may recommend nominees to the Boards of Directors of Puget Energy and PSE. Members of the Boards of Directors of Puget Energy and PSE are nominated and elected in accordance with the provisions of their respective Amended and Restated Bylaws.

Code of Conduct

Puget Energy and PSE have adopted a Corporate Ethics and Compliance Code applicable to all directors, officers and employees and a Code of Ethics applicable to the Chief Executive Officer and senior financial officers, which are available on the website www.pugetenergy.com. If any material provisions of the Corporate Ethics and Compliance Code or the Code of Ethics are waived for the Chief Executive Officer or senior financial officers, or if any substantive changes are made to either code as they relate to any director or executive officer, we will disclose that fact on our website within four business days. In addition, any other material amendments of these codes will be disclosed.

Communications with the Board

Interested parties may communicate with an individual director or the Board of Directors as a group via U.S. Postal mail directed to: Chairman of the Board of Directors, c/o Corporate Secretary, Puget Energy, Inc., P.O. Box 97034, EST-11, Bellevue, Washington 98009-9734. Please clearly specify in each communication the applicable addressee or addressees you wish to contact. All such communications will be forwarded to the intended director or Board as a whole, as applicable.

ITEM 11. EXECUTIVE COMPENSATION

Puget Sound Energy
Executive Compensation

Compensation and Leadership Development Committee Interlocks and Insider Participation

The members of the Compensation and Leadership Development Committee (referred to as the Committee) of the Boards of Directors (referred to as the Board) of Puget Energy and PSE (referred to as the Company) are named in the Compensation and Leadership Development Committee Report. No members of the Committee were officers or employees of the Company or any of its subsidiaries during 2022, nor were they formerly Company officers or had any relationship otherwise requiring disclosure. Each member meets the independence requirements of the SEC and the New York Stock Exchange (NYSE).

Compensation Discussion and Analysis

This section provides information about the compensation program for the Company's named executive officers (Named Executive Officers) who are included in the Summary Compensation Table below. For 2022, the Company's Named Executive Officers and titles were:

- Mary E. Kipp, President and Chief Executive Officer (CEO);
- Kazi Hasan, Executive Vice President and Chief Financial Officer (CFO);
- Allan (Wade) Smith, Executive Vice President and Chief Operating Officer, effective July 18, 2022;
- Margaret F. Hopkins, Senior Vice President Shared Services and Chief Information Officer;
- Andy Wappler, Senior Vice President and Chief Customer Officer; and
- Steve R. Secrist, former Senior Vice President, General Counsel, Chief Ethics and Compliance Officer who retired effective December 1, 2022.

This section also includes a discussion and analysis of the overall objectives of our compensation program and each element of compensation the Company provides to its Named Executive Officers.

Compensation Program Objectives

The Company's executive compensation program has two main objectives:

- Support sustained Company performance by attracting, retaining and motivating talented people to run the business.
- Align incentive compensation payments with the achievement of short and long-term Company goals.

The Committee is responsible for developing and monitoring an executive compensation program and philosophy that achieves the foregoing objectives. In performing its duties, the Committee obtains information and advice on various aspects of the executive compensation program from its independent executive compensation consultant, Meridian Compensation Partners, LLC (Meridian). The Committee recommends to the Board for approval both the salary level for our CEO, based on information provided by Meridian and other relevant factors described below, and the salary levels for the other executives, based on recommendations from our CEO. The Committee also recommends to the Board for approval the annual and long-term incentive compensation plans for the executives, the setting of performance goals and the determination of target and actual awards under those plans, based on the compensation information provided by Meridian and other relevant factors.

In 2022, the Company used the following strategies to achieve the objectives of our executive compensation program:

- **Design and deliver a competitive total compensation opportunity.** To attract, retain and motivate a talented executive team, the Company believes that total pay opportunity should be competitive with companies of similar size, revenue, industry and scope of operations. As described below in the discussion of Role of Market Data, the Committee, with the support of Meridian, annually compares executive compensation levels to external market data from similar companies in our industry and generally targets each element of target total direct compensation (base salary and target annual and long-term incentive award opportunities) to the 50th percentile of the market data with variations by individual executive, as appropriate. The Company also recognizes the importance of providing retirement income. As such, the Committee reviews our retirement programs and provides benefits that are competitive with our peers.

- **Place a significant portion of each executive's target incentive compensation at risk to align executive compensation with Company financial and operating performance.** Under its "pay for performance" philosophy, the Company maintains an incentive compensation program that supports the Company's business strategy and aligns executive interests with those of investors and customers. The Committee believes that a significant portion of each executive's compensation should be "at risk" and earned based on achievement relative to annual and long-term performance goals. For example, 77% of the target 2022 compensation of our CEO, Ms. Kipp, was considered "at risk" compensation. By establishing goals, monitoring results, and rewarding achievement of goals, the Company seeks to focus executives on actions that will improve Company performance and enhance investor value, while also retaining key talent. The Committee annually evaluates and establishes the performance goals and targets for our annual and long-term incentive programs.
- **Oversee the Company's talent management process to ensure that executive leadership continues uninterrupted by executive retirements or other personnel changes.** The CEO leads talent reviews for leadership succession planning through meetings and discussions with her executive team. Each executive conducts talent reviews of senior employees that report to him or her and who have high potential for assuming greater responsibility in the Company. Utilizing evaluations and assessments, the Committee and the Board annually review these assessments of executive readiness, the plans for development of the Company's key executives, and progress made on these succession plans. The Committee and the Board directly participate in discussion of succession plans for the position of CEO.

Compensation Philosophy

The target total compensation package is designed to provide executives with appropriate incentives that are competitive with the comparator groups described below and motivate the achievement of current operational performance and customer service goals as well as the long-term objective of enhancing investor value. The Company does not have a specific policy regarding the mix of compensation elements, although long-term incentive awards consistently comprise the largest portion of each executive's incentive pay.

As a matter of philosophy, all three components of target total direct compensation are generally targeted within a competitive range of the 50th percentile of industry practice, recognizing that the Company operates in a highly competitive regional market. Individual executive pay position may vary from the 50th percentile as influenced by the factors below. Actual executive compensation depends significantly on Company performance results, and can result in below or above targeted levels.

Individual pay adjustments are reviewed annually relative to the 50th percentile of national peer market pay, while also considering other factors, such as the executive's recent performance, experience level, company performance, competitive pay in our region, retention of top talent and internal pay equity. Notwithstanding the median philosophy, the Company may choose to target an executive's compensation above or below the 50th percentile of national peer market pay when that individual has a role with greater or lesser responsibility than the best comparison job, in response to regional market pressures, or when our executive's experience differs from that typically found in the market.

Role of Market Data

The Company uses market data compiled by Meridian to inform its pay decisions on base salary, target annual incentives and target long-term incentive awards. Market data is obtained from both industry-specific surveys and proxy statements of public companies selected for inclusion in the Company's custom executive compensation peer group. The market survey data were sourced from a select cut from the Willis Towers Watson 2021 Energy Services Survey, comprised of utility and other companies similar in size and scope of operations to PSE. Based on Meridian's evaluation and its discussion with the Committee, five companies of similar scope were added to the 2021 peer group, while one was removed to ensure a broad comparison group. The 26 companies in the custom market survey cut for 2022 pay decisions are shown below:

Custom Survey Peer Group

1. Allete*	10. Evergy	19. PNM Resources
2. Alliant Energy	11. Eversource Energy	20. Portland General Electric
3. Ameren	12. Hawaiian Electric Industries, Inc.	21. PPL*
4. Atmos Energy	13. NiSource	22. South Jersey Industries
5. Avista	14. Northwestern Energy*	23. Southwest Gas
6. Black Hills*	15. Oncor	24. Spire
7 CenterPoint*	16. OGE Energy	25. UGI
8 Cleco	17. ONE Gas	26. WEC Energy Group
9. CMS Energy	18. Pinnacle West Capital	

**Added to the 2021 peer group. Avangrid was removed from the 2021 peer group.*

The market survey data from the companies above were supplemented with proxy statement data for select positions in the Company's executive compensation peer group, which was comprised of 15 companies, all but one of which overlapped with companies included in the market survey data. At the time of the benchmarking study, the median revenue of the executive compensation peers was $3.5 billion, which was comparable to PSE's annual revenues of $3.5 billion. The proxy peer group was reviewed by Meridian to assess the continued relevancy of the companies and did not change from last year.

Proxy Peer Group

1. Alliant Energy	7. Eversource Energy	13. Portland General Electric
2. Ameren	8. Idacorp	14. Spire
3. Atmos Energy	9. NiSource	15. WEC Energy Group
4. Avista	10. ONE Gas	
5. CMS Energy	11. Pinnacle West Capital	

6. Evergy 12. PNM Resources

Compensation Program Elements

The Company’s executive compensation program encompasses a mix of base salary, annual and long-term incentive compensation, retirement programs, health and welfare benefits and a limited number of perquisites. Since the Company is not publicly listed and does not grant equity awards to its executives, it relies on a mix of fixed and variable cash-based compensation elements to achieve its compensation objectives.

Base Salary

We recognize that it is necessary to provide executives with a fixed amount of regularly paid compensation that provides a balance to other at-risk pay elements. Base salaries are reviewed annually by the Committee based on its compensation philosophy, internal pay equity considerations and considerations specific to an individual such as an executive’s expertise, level of performance, experience in the role and contribution relative to others in the organization.

Base Salary Adjustments for 2022

The Committee reviewed the base salaries of the Named Executive Officers in early 2022 and recommended base salary adjustments to the Board, except for Mr. Smith, whose salary was approved at hire in July 2022. The Committee also reviewed salaries during 2022 based on market pressures and the promotion of Mr. Hasan to Executive Vice President and recommended base salary increases. The Board approved the Committee’s salary recommendations as shown in the table below. The adjustments were effective March 1, 2022 except for Ms. Kipp’s and Mr. Hasan’s who also received additional adjustments effective August 2022. Base salaries for 2022 generally remained at the 50th percentile of market among the comparator group.

Name	2021 Base Salary	2022 Base Salary	% Change[1]
Mary E. Kipp	$930,000	$1,043,250	12%
Kazi Hasan	510,000	570,257	12
Allan (Wade) Smith	N/A	630,000	—
Margaret F. Hopkins	414,000	426,482	3
Andrew Wappler	390,326	402,036	3
Steve R. Secrist	500,553	515,570	3

1. *Percentages are rounded.*

2022 Annual Incentive Compensation

All PSE employees, including the Named Executive Officers, are eligible to participate in an annual incentive program referred to as the “Goals and Incentive Plan”. The plan is designed to incent our employees to achieve both (i) desired annual financial results, measured by EBITDA, and (ii) pre-established goals based on both a service quality commitment to customers and an employee safety measure. EBITDA was selected as a performance goal because it provides a financial measure of cash flows generated from the Company’s annual operating performance.

For 2022, the Company’s service quality commitment was measured by performance against nine Service Quality Indicators (SQIs) covering three broad categories, set forth below. These are the same SQIs for which the Company is accountable to the Washington Commission. The Company's annual report to the Washington Commission and our customers describes each SQI, how it is measured, the Company’s required level of achievement, and performance results. The Company’s service quality report cards are available at www.PSE.com/PerformanceReportCards.

The SQIs for 2022 were the same as those in 2021 and were as follows:

- **Customer Satisfaction (3 SQIs) -** Customer satisfaction with the customer care center, natural gas field services and number of Washington Commission complaints.
- **Customer Service (1 SQI)** - Calls answered “live” within 60 seconds by the customer care center.
- **Operations Services (5 SQIs)** - Gas emergency response, electric emergency response, non-storm outage duration as measured by the System Average Interruption Disruption Index (SAIDI), non-storm outage frequency, and on-time appointments.

The employee safety performance measure reflects the Company’s continued commitment to employee safety. The safety performance measure contains three targets which must all be satisfied for the safety measure to be treated as met. The three employee safety targets for 2022 were:

- All employees attend a monthly safety “meeting in a box” presentation, or complete the same content online, featuring employees from across PSE discussing their jobs and efforts to ensure the health and safety of themselves, their coworkers and our customers. The target completion rate is no less than 95%.
- All employees complete training videos to help reduce musculoskeletal injuries in the field, officer and at home. The target completion rate is no less than 95%.

- All employees complete an online mental health training course. The target completion rate is no less than 95%.

Annual incentive funding is decreased if a SQI is not achieved. The employee safety measure functions similarly to the nine SQIs in determining the funding of the annual incentive plan. That is, if the safety measure is not achieved, annual incentive funding will be decreased by 10%, in the same way as a missed SQI.

In 2022, 100% funding for the annual incentive plan required (i) achievement of 10 out of 10 customer service and safety measures (all nine SQIs and achievement of the safety measure) and (ii) target EBITDA performance. Eight of the ten

customer service and safety measures were met, and EBITDA finished at 98.4% of target, so funding was less than 100%, as described further below.

2022 Annual Incentive Plan Results

For 2022, achievement of the corporate goals under the annual incentive plan was at 98.4% of target for EBITDA. PSE EBITDA was $1,293.6 million, and SQI and safety achievement was 8 out of 10, leading to a funding level for 2022 of 73.5% for the annual incentive plan for the Named Executive Officers.

Funding levels for 2022 at maximum, target, and threshold are shown in the table below:

Annual Incentive Performance Payout Scale and Actual Performance

Performance Measure (Dollars in Millions)	2022 EBITDA	SQI, SAIDI& Safety*	Funding Level
Maximum	$ 1,775.3	10/10	200%
Target	1,315.0	10/10	100
Threshold	1,183.5	6/10	30
2022 Actual Performance	1,293.6	8/10	73.5

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* *Combined SQI and Safety results of 6/10 or better and minimum EBITDA of $1,183.5 million are required for any annual incentive pay out funding*
SQI and Safety results below 10/10 reduce funding (e.g., 9/10=90%, 8/10=80%, 7/10=70%)

No bonus is earned unless at least the threshold EBITDA and SQI and safety goals are achieved. The achievement of threshold performance results in a 30% of target bonus payout. The maximum incentive payable for exceptional performance in this plan is two times each Named Executive Officer's target incentive.

An executive’s individual award amount can be increased or decreased based on an assessment by the CEO (or the Board in the case of the CEO) of the executive’s individual and team performance results. After considering performance on individual and team goals, adjustments were made by the CEO for individual performance of certain Named Executive Officers below CEO in 2022. The adjustments for individual performance are noted in the "Bonus" column of the Summary Compensation table and did not materially change the amounts resulting from 2022 achievement of the corporate goals. The Board approved the incentive amounts shown below (inclusive of adjustments for performance for each Ms. Kipp and Mr. Hasan), which will be paid in March 2023:

Name	Target Incentive (% of Base Salary)	2022 Actual Incentive Paid	2022 Actual Incentive (% of Base Salary)
Mary E. Kipp	115%	$ 1,058,168	101.0%
Kazi Hasan*	80	352,109	62
Allan (Wade) Smith*	80	179,895	29
Margaret F. Hopkins	65	193,565	45
Andrew Wappler	65	182,469	45
Steve R. Secrist	65	246,314	48

* *Mr. Hasan’s annual incentive is based on time as Senior Vice President (65%) and time as Executive Vice President (80%); Mr. Smith’s annual incentive is prorated for time worked in 2022 since his hire. His target annual incentive is 80% of base salary.*

Long-Term Incentive Compensation

Long-term incentive compensation opportunities are designed to align the interests of executives with those of our investors, provide competitive pay opportunities, support a customer-focused utility, reward long-term performance and promote retention. Long term incentive plan (LTI Plan) grants are denominated and paid in cash, if at least threshold performance measures are met over a three-year performance cycle.

Long-term incentive payments are based on achievement of a Return on Equity (ROE) metric, subject to achievement of a threshold EBITDA goal. Under this goal, EBITDA during the applicable three-year performance cycle must meet or exceed 90% of target EBITDA for a payment to occur. Assuming the EBITDA threshold is met, the grant cycles are funded based on the three-year average ROE metric. ROE reflects the income earned on our equity investment. The LTI Plan payments ultimately paid may range from 0% to 200% of target, depending on performance.

The Committee recommends for Board approval a targeted LTI grant value in dollars for each executive. The targeted LTI grant value is determined by evaluating LTI grant values provided to similarly situated executives at comparable companies (using the previously discussed survey and peer group data) as well as other relevant executive-specific factors. The Company generally does not consider previously granted awards or the level of accrued value from prior or other programs when making new LTI Plan grants.

Executives generally must be employed on the last day of the performance cycle to receive a cash payment under the LTI Plan, except in the event of retirement, disability or death.

2022-2024 Long-Term Incentive Plan Target Awards

Consistent with prior years, target LTI Plan awards for the 2022-2024 performance cycle were denominated in dollars, taking into account the executive's level of responsibility within the Company and the corresponding market data. Ms. Kipp's target LTI Plan grant was increased to $3,700,000 to align with market pay levels. Target LTI Plan award amounts for the 2022-2024 performance cycle are shown in the following table.

Name	Target Long Term Incentive ($)
Mary E. Kipp	$3,700,000
Kazi Hasan	1,000,000
Allan (Wade) Smith	1,260,000
Margaret F. Hopkins	405,000
Andrew Wappler	380,000
Steve R. Secrist	490,000

Details of the target grants and expected values at target, threshold and maximum performance levels can be found in the "2022 Grants of Plan-Based Awards" table below.

Long-Term Incentive Plan Performance 2020-2022 Performance Cycle Results and Payouts

The 2020-2022 performance cycle has now ended. Amounts payable as a result of award vesting are shown in the following table:

- Performance on the ROE component of the grant finished at 80% of target, which was below the plan's threshold for funding. The Committee recommended and the Board approved a payment at 110% of target funding level, in recognition of the initial targets being set prior to the COVID global pandemic and the impact that had on business and regulatory conditions.

Name	Target Incentive ($)[1]	2020-2022 LTIP Paid[2]
Mary E. Kipp	$2,385,000	$2,623,500
Kazi Hasan[2]	375,000	412,500
Allan (Wade) Smith[2]	—	—
Margaret F. Hopkins	293,125	322,438
Andrew Wappler	169,178	186,096

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[1] *Target LTI Plan incentive is the dollar target level set in 2020.*

[2] *In connection with Mr. Hasan's commencement of employment in 2021, he was eligible to participate in the 2020-2022 performance cycle at a target amount that reflected reduced participation during the performance cycle but was intended to incentivize performance following commencement of employment. In connection with Mr. Smith's commencement of employment in 2022, he was granted retention incentives described in the "Other Compensation" section below. He did not receive a grant in the 2020-2022 LTIP performance cycle.*

In connection with Mr. Secrist's retirement, he was eligible to receive a pro-rated portion of his LTI grants for the 2020-2022, 2021-2023 and 2022-2024 performance cycles in accordance with the LTI Plan in the amounts of $505,389, $233,641 and $134,260, respectively, paid in March 2023.

Retirement Plans –– Executive Retirement Plans and Retirement Plan

The Company maintains executive retirement plans to attract and retain executives by providing a benefit that is coordinated with the tax-qualified

Retirement Plan for Employees of Puget Sound Energy, Inc. (Retirement Plan). Without the addition of the executive retirement plans, these executives would receive lower percentages of replacement income during retirement than other employees. All the Named Executive Officers participated in executive retirement plans during 2022, Ms. Hopkins and Mr. Wappler participate in the SERP and Ms. Kipp, Mr. Hasan and Mr. Smith participate in the Officer Restoration Benefit, as part of the Deferred Compensation Plan for Key Employees. Mr. Secrist participated in the SERP until his departure in 2022. Additional information regarding the SERP, Officer Restoration Benefit and the Retirement Plan is shown in the “2022 Pension Benefits” table.

Deferred Compensation Plan

The Named Executive Officers are eligible to participate in the Deferred Compensation Plan for Key Employees (Deferred Compensation Plan). The Deferred Compensation Plan provides eligible executives an opportunity to defer up to 100% of base salary, annual incentive bonuses and earned LTI Plan awards, plus receive additional Company contributions made by PSE into an account that has three investment tracking fund choices. The funds mirror performance in major asset classes of bonds, stocks, and an interest crediting fund that changes rates quarterly. The Deferred Compensation Plan is intended to allow the executives to defer current income, without being limited by the Internal Revenue Code contribution limitations for 401(k) plans and therefore have a deferral opportunity similar to other employees as a percentage of eligible compensation. The Company contributions are also intended to restore benefits not available to executives under PSE’s tax-qualified plans due to Internal Revenue Code limitations on compensation and benefits applicable to those plans. Additional information regarding the Deferred Compensation Plan is shown in the “2022 Nonqualified Deferred Compensation” table.

Post-Termination Benefits

The Committee periodically reviews existing change in control and severance arrangements for the peer group companies. Based on this information, the Committee has determined not to extend such arrangements to current and newly hired executives. No executive officers have employment agreements that would provide severance benefits. Certain compensation programs, such as the LTI Plan, have provisions that would apply in the event of a change in control.

The “Potential Payments Upon Termination or Change in Control” section describes the current post-termination arrangements with the Named Executive Officers as well as other plans and arrangements that would provide benefits on termination of employment or a change in control, and the estimated potential incremental payments upon a termination of employment or change in control based on an assumed termination or change in control date of December 31, 2022.

Other Compensation

The Company also provides the Named Executive Officers with benefits and limited perquisites. To attract qualified candidates, the Company may provide certain payments to executives in connection with an offer of employment, including payments to offset their relocation expenses.

In connection with his offer of employment in 2021, Mr. Hasan is eligible to receive a retention bonus of $250,000 in each of March 2022 and March 2023, subject to continued employment.

In connection with his offer of employment, Mr. Smith was eligible to receive a signing bonus of $900,000 and a relocation payment of $150,000, grossed up for taxes, to assist with moving expenses. Both amounts must be repaid if Mr. Smith resigns or is terminated for cause within 24 months of employment. Subject to continued employment, Mr. Smith is eligible to receive a retention bonus of $630,000 in March 2023, $150,000 in July 2023 (after one year of service) and $1,260,000 in December 2026. Mr. Smith is also eligible to participate in the 2021-2023 performance cycle under the LTI Plan based on a target grant of $945,000 in addition to participation in the 2022-2024 performance cycle for which disclosure is provided above.

The current executives participate in the same group health and welfare plans as other employees. Company vice presidents and above, including the Named Executive Officers, are eligible for additional disability and life insurance benefits. The executives are also eligible to receive reimbursement for financial planning, tax preparation and legal services up to an annual limit. The reimbursement for financial planning, tax preparation and legal services is provided to allow executives to concentrate on their business responsibilities. These perquisites generally do not make up a significant portion of executive

compensation and did not exceed $10,000 in total for each Named Executive Officer in 2022. Executives are taxed on the value of the perquisites received, with no corresponding gross-up by the Company.

Relationship among Compensation Elements

A number of compensation elements increase in absolute dollar value as a result of increases to other elements. Base salary increases translate into higher dollar value opportunities for annual incentives, because the plan operates with a target award set as a percentage of base salary. Base salary increases also increase the level of retirement benefits, as do actual annual incentive plan payments. Some key compensation elements are excluded from consideration when determining other elements of pay. Retirement benefits exclude LTI Plan payments in the calculation of qualified retirement (pension and 401(k)) and SERP benefits.

Impact of Accounting and Tax Treatment of Compensation

The accounting treatment of compensation generally has not been a significant factor in determining the amounts of compensation for our executive officers. However, the Company considers the tax impact of various program designs to balance the potential cost to the Company with the benefit/value to the executive. As a result of changes in federal tax law effective in 2018, the Company is now subject to IRS section 162(m). Section 162(m) limits the tax deductibility of compensation paid to certain executive officers, including the Named Executive Officers, to $1 million per year. Notwithstanding the new tax law, the Company does not expect to make changes in its executive compensation program designs and retains the discretion to pay compensation that may not qualify for a tax deduction.

Risk Assessment

A portion of each executive's total direct compensation is variable, at risk and tied to the Company's financial and operational performance to motivate and reward executives for the achievement of Company goals. The Company's variable pay program helps executives focus on interests important to the Company and its investors and customers and creates a record of their results. In structuring its incentive programs, the Company also strives to balance and moderate risk to the Company from such programs: individual award opportunities are defined and subject to limits, goal funding is based on collective company performance, annual incentive awards are balanced by long-term incentive awards that measure performance over three years, performance targets are based on management's operating plan (which includes providing good customer service), and all incentive awards to individual executives are subject to discretionary review by management, the Committee and/or the Board. As a result, the Committee and the Board believe that the programs' design do not have risks that are reasonably likely to have a material adverse effect on the Company and also provide appropriate incentive opportunities for executives to achieve Company goals that support the interests of our investors and customers.

Compensation and Leadership Development Committee Report

The Board delegates responsibility to the Compensation and Leadership Development Committee to establish and oversee the Company's executive compensation program. Each member of the Committee served during all of 2022, except Mr. Rubin who joined February 22, 2022.

The Committee members listed below have reviewed and discussed the "Compensation Discussion and Analysis" with the Company's management. Based on this review and discussion, the Committee recommended to the Board, and the Board has approved, that the "Compensation Discussion and Analysis" be included in the Company's Annual Report on Form 10-K for the year ended December 31, 2022, for filing with the SEC.

Compensation and Leadership
Development Committee of
Puget Energy, Inc.
Puget Sound Energy, Inc.

Steven Zucchet, chair,
Scott Armstrong
Barbara Gordon
Aaron Rubin, effective February 22, 2022
Martijn Verwoest

Summary Compensation Table

The following information is provided for the year ended December 31, 2022, (and for prior years where applicable) with respect to the Named Executive Officers during 2022. The positions listed below are at Puget Energy and PSE, except that Ms. Hopkins and Mr. Wappler are executives of PSE only. Positions listed are those held by the Named Executive Officers as of December 31, 2022. Salary and incentive compensation includes amounts deferred at the executive's election.

Name and Principal Position	Year	Salary	Bonus[1]	Stock Awards	Option Awards	Non-Equity Incentive Plan Compensation[2]	Change in Pension Value and Nonqualified Deferred Compensation Earnings[3]	All Other Compensation[4]	Total
Mary E. Kipp	2022	$ 991,585	$176,361	$ —	$ —	$ 3,505,307	$ —	$ 87,678	$ 4,760,931
President and,	2021	$ 923,923	$ —	$ —	$ —	$ 3,388,708	$ —	$ 101,614	$ 4,414,245
Chief Executive Officer[5]	2020	891,667	—	—	—	2,847,229	—	1,557,670	5,296,566
Kazi Hasan, Executive Vice	2022	542,348	308,685	—	—	705,924	—	54,849	1,611,806
President and Chief Financial Officer[6]	2021	243,409	262,736	—	—	294,118	—	315,817	1,116,080
Allan (Wade) Smith, Executive Vice President and Chief Operating Officer[7]	2022	262,500	900,000	—	—	179,895	—	223,747	1,566,142
Margaret F. Hopkins	2022	423,946	—	—	—	516,002	60,088	42,761	1,042,797
Senior Vice President Shared	2021	400,984	—	—	—	381,070	505,621	37,694	1,325,369
Services and CIO[8]	2020	345,328	—	—	—	461,260	499,683	39,064	1,345,335
Andrew Wappler									
Senior Vice President and Chief Customer Officer[9]	2022	399,645	—	—	—	368,565	—	29,104	797,314
Steve R. Secrist	2022	491,021				246,314	343,636	923,664	2,004,635
Former Senior Vice President	2021	497,096	—	—	—	828,788	524,937	49,050	1,899,871

General Counsel, Chief Ethics & Compliance Officer[10]	2020	479,287	—	—	—	1,105,450	658,689	51,325	2,294,751

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1. *Reflects individual performance above target as described in the "Compensation Discussion and Analysis," section titled "2022 Annual Incentive Plan Results" for each of Ms. Kipp and Mr. Hasan. For Mr. Hasan, also reflects a retention bonus of $250,000 paid in 2022 in connection with the terms of his 2021 offer of employment.. For Mr. Smith also reflects a signing bonus paid in connection with commencement of employment in 2022, in the amount of $900,000.*
2. *For 2022, reflects annual cash incentive compensation paid under the 2022 Goals and Incentive Plan and cash incentive compensation paid under the LTI Plan for the 2020-2022 performance cycle. Cash incentive amounts were paid in early 2023 or deferred at the executive's election. The 2022 Goals and Incentive Plan and the LTI Plan are described in further detail under "Compensation Discussion and Analysis," including the individual amounts paid to each Named Executive Officer in early 2023.*
3. *Reflects the aggregate increase in the actuarial present value of the executive's accumulated benefit under all pension plans during the year. The amounts are determined using interest rate and mortality rate assumptions consistent with those used in the Company's financial statements and include amounts that the executive may not currently be entitled to receive because such amounts are not vested. In 2022, updated interest rates relative to those used for 2021 have generally resulted in smaller increases in value than in prior years. Information regarding these pension plans is set forth in further detail under "2022 Pension Benefits." The change in pension value amounts for 2022 are: Ms. Kipp, $0; Mr. Hasan, $0; Mr. Smith, $0; Ms. Hopkins, $60,088; Mr. Wappler, $0; and Mr. Secrist, $343,636.*
4. *All Other Compensation for 2022 is shown in detail in the table below.*
5. *Ms. Kipp joined PSE and Puget Energy as President on August 31, 2019, and became President and CEO on January 3, 2020.*
6. *Mr. Hasan joined PSE and Puget Energy as Senior Vice President and Chief Financial Officer on June 24, 2021.*
7. *Mr. Smith joined PSE and Puget Energy as Executive Vice President and Chief Operating Officer on July 18, 2022.*
8. *Ms. Hopkins has worked at PSE since 2009.*
9. *Mr. Wappler has worked at PSE since February 2008.*
10. *Mr. Secrist has worked at PSE since May 1989 and retired effective December 1, 2022.*

Detail of All Other Compensation

Name	Perquisites and Other Personal Benefits[1]	Registrant Contributions to Defined Contribution and Deferred Compensation Plans[2]	Other[3]
Mary E. Kipp	$ 5,000	$ 70,381	$ 12,297
Kazi Hasan	—	45,804	9,045
Allan (Wade) Smith	150,000	11,025	62,722
Margaret F. Hopkins	—	36,585	6,176
Andrew Wappler	—	21,200	7,904
Steve R. Secrist	2,500	41,569	879,596

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1. *Reimbursement for financial planning, tax planning, and/or legal planning, with the initial plan up to a maximum of $5,000, and then annual reimbursement up to a maximum of $5,000 for Ms. Kipp, and $2,500 for the other Named Executive Officers. For Mr. Smith, also includes a relocation payment of $150,000, as described in "Other Compensation" of the "Compensation Discussion and Analysis."*
2. *Includes Company contributions during 2022 to PSE's Investment Plan (a tax qualified 401(k) plan) and the Deferred Compensation Plan. Company 401(k) contributions are as follows: Ms. Kipp, $25,325; Mr. Hasan, $23,376; Mr. Smith, $11,025; Ms. Hopkins $17,205; Mr. Wappler, $21,200; and Mr. Secrist, $18,402. Company contributions to the Deferred Compensation Plan are as follows: Ms. Kipp, $45,056; Mr. Hasan, $22,428; Mr. Smith, $0; Ms. Hopkins, $19,3802; Mr. Wappler, $0; and Mr. Secrist, $23,167.*
3. *Reflects the value of imputed income for life insurance and Company paid premiums on supplemental disability insurance for all Named Executive Officers. For Mr. Smith, also includes the amount of a tax gross-up on relocation payments of $58,548, as described in the "Compensation Discussion and Analysis," "Other Compensation". For Mr. Secrist also includes pro-rated payment of LTI Plan grants at retirement, per the LTI Plan terms: 2020-2022 $505,389; 2021-2023, $233,641; and 2022-2024, $134,260.*

2022 Grants of Plan-Based Awards

The following table presents information regarding 2022 grants of non-equity annual incentive awards and LTI Plan awards, including, as applicable, the range of potential payouts for the awards.

		Estimated Future Payouts under Non-Equity Incentive Plan Awards			
Name	Grant Date	Grant Target Value	Threshold	Target	Maximum

Mary E. Kipp					
Annual Incentive[1]	1/1/2022		$ 359,921	$ 1,199,738	$ 2,399,475
LTI Plan 2022-2024[2]	2/24/2022	3,700,000	1,850,000	3,700,000	7,400,000
Kazi Hasan					
Annual Incentive[1]	1/1/2022		$ 119,765	$ 399,217	$ 798,434
LTI Plan 2022-2024[2]	2/24/2022	1,000,000	500,000	1,000,000	2,000,000
Allan (Wade) Smith					
Annual Incentive[1]	7/18/2022		$ 69,930	$ 233,100	$ 466,200
LTI Plan 2021-2023[3]	7/18/2022	945,000	472,500	945,000	1,890,000
LTI Plan 2022-2024[2]	7/18/2022	1,260,000	630,000	1,260,000	2,520,000
Margaret F. Hopkins					
Annual Incentive[1]	1/25/2022		$ 83,164	$ 277,214	$ 554,428
LTI Plan 2022-2024[2]	2/24/2022	405,000	202,500	405,000	810,000
Andrew Wappler					
Annual Incentive[1]	1/1/2022		$ 78,397	$ 261,323	$ 522,647
LTI Plan 2022-2024[2]	2/24/2022	380,000	190,000	380,000	760,000
Steve R. Secrist					
Annual Incentive[1,4]	1/1/2022		$ 100,536	$ 335,121	$ 670,241
LTI Plan 2022-2024[4]	2/24/2022	490,000	245,000	490,000	980,000

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1. *As described in the "Compensation Discussion and Analysis," the 2022 Goals and Incentive Plan had dual funding triggers in 2022 of $1,183.5 million EBITDA and SQI performance of 6/10. Payment would be $0 if either trigger is not met. The threshold estimate assumes $1,183.5 million EBITDA and SQI/Safety measure performance at 6/10. The target estimate assumes $1,315.0 million EBITDA and SQI/Safety measure performance at 10/10. The maximum estimate assumes $1,775.3 million EBITDA or higher and SQI/Safety measure performance at 10/10. The award for Mr. Smith was pro-rated for time worked in 2022 per the plan.*
2. *As described in the "Compensation Discussion and Analysis," LTI Plan grants for the 2022-2024 performance cycle were allocated 100% to a ROE component subject to achievement of an EBITDA threshold goal.*
3. *In connection with Mr. Smith's commencement of employment, he was eligible to participate in the LTI Plan for the performance cycle indicated, but at a reduced participation level, as described in the "Compensation Discussion and Analysis.".*
4. *Mr. Secrist received full grants on the grant dates in the amounts shown, but upon retirement had earned pro-rate portions per the plans, in the amounts shown in the Summary Compensation Table for 2022.*

2022 Pension Benefits

The Company and its affiliates maintain two pension plans: the Retirement Plan and the SERP, in addition to an Officer Restoration Benefit as part of the Deferred Compensation Plan. The following table provides information for the participating Named Executive Officers regarding the actuarial present value of the executive's accumulated benefit and years of credited service under the Retirement Plan and the SERP. The present value of accumulated benefits was determined using interest rate and mortality rate assumptions consistent with those used in the Company's financial statements. Each of the Named Executive Officers participates in both plans, except Ms. Kipp and Mr. Hasan, who participate just in the Officer Restoration Benefit (which is reported separately below) and Mr. Smith who participates in the Retirement Plan and the Officer Restoration Benefit.

Name	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefit [1,2]	Payments During Last Fiscal Year
Mary E. Kipp[3]	Retirement Contribution	3.3	$ —	$ —
	Restoration Benefit	3.3	—	—
Kazi Hasan[3]	Retirement Contribution	1.5	—	—
	Restoration Benefit	1.5	—	—
Allan (Wade) Smith	Retirement Plan	4	—	—
	Restoration Benefit	4	—	—
Margaret F. Hopkins	Retirement Plan	13.3	373,812	—

	SERP	13.3	2,520,337	—
Andrew Wappler	Retirement Plan	14.8	512,011	—
	SERP	14.8	2,513,830	—
Steve R. Secrist	Retirement Plan	33.5	979,620	—
	SERP	33.5	—	4,855,525

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1. *The amounts reported in this column for each executive were calculated assuming no future service or pay increases. Present values were calculated assuming no pre-retirement mortality or termination. The values under the Retirement Plan and the SERP are the actuarial present values as of December 31, 2022, of the benefits earned as of that date and payable at normal retirement age (age 65 for the Retirement Plan and age 62 for the SERP). Future cash balance interest credits are assumed to be 4.0% annually. The discount assumption is 5.60%, and the post-retirement mortality assumption is based on the 2023 417(e) unisex mortality table. Annuity benefits are converted to lump sum amounts at retirement based on assumed future 417(e) segment rates of 1.41%, 3.09%, and 3.58% (the 24-month average of the underlying rates as of September 2022), except that payments assumed to occur during 2023 use segment rates in effect for 2023 (this does not apply to any Named Executive Officers this year). These assumptions are consistent with the ones used for the Retirement Plan and the SERP for financial reporting purposes for 2022. In order to determine the change in pension values for the Summary Compensation Table, the values of the Retirement Plan and the SERP benefits were also calculated as of December 31, 2021, for the benefits earned as of that date using the assumptions used for financial reporting purposes for 2021. These assumptions included assumed cash balance interest credits of 4.0%, a discount assumption of 3.00% and post-retirement mortality assumption based on the 2022 417(e) unisex mortality table. Annuity benefits were converted to lump sum amounts at retirement based on assumed future 417(e) segment rates of 1.07%, 2.68%, and 3.36% (the 24-month average of the underlying rates as of September 2021). Other assumptions used to determine the value as of December 31, 2021, were the same as those used for December 31, 2022.*

2. *As described in footnote 1 above, the amounts reported for the SERP in this column are actuarial present values, calculated using the actuarial assumptions used for financial reporting purposes. These assumptions are different from those used to calculate the actual amount of benefit payments under the SERP (see text below for a discussion of the actuarial assumptions used to calculate actual payment amounts). The following table shows the estimated lump sum amount that would be paid under the SERP to each SERP-eligible Named Executive Officer at age 62 (without discounting to the present), calculated as if such Named Executive Officer had terminated employment on December 31, 2022. Each SERP-eligible Named Executive Officer was vested in his or her SERP benefits as of December 31, 2022.*

Name	Estimated Lump Sum
Margaret F. Hopkins	3,162,728
Andrew Wappler	3,126,019

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3. *Ms. Kipp, Mr. Hasan and Mr. Smith do not have SERP benefits as that plan was closed prior to their joining PSE. Ms. Kipp and Mr. Hasan do not have a Retirement Plan benefit, as upon hire, each elected to have their 4% company retirement contribution made to their 401(k) accounts. Based on service through December 31, 2022 these 401 (k) accounts had values of: Ms. Kipp, $40,932; Mr. Hasan, $20,105; and Mr. Smith, $10,500. Ms. Kipp, Mr. Hasan and Mr. Smith also participate in the Officer Restoration Benefit Plan as described below, with vesting after three years of service. The value of these Officer Restoration accounts based on service through December 31, 2022 are: Ms. Kipp, $127,426; and Mr. Hasan, $20,294, Mr. Smith's first Officer Restoration account contribution will be made in 2023.*

4. *As a result of retirement on December 1, 2022, Mr. Secrist received a SERP lump sum in the amount of $4,855,525, calculated per the plan and paid according to Mr. Secrist's payment election.*

Retirement Plan

Under the Retirement Plan, the Company's eligible employees hired prior to January 1, 2014 (prior to December 12, 2014, in the case of IBEW-represented employees), including the participating Named Executive Officers, accrue benefits in accordance with a cash balance formula, beginning on the later of their date of hire or March 1, 1997. Under this formula, for each calendar year after 1996, age-weighted pay credits are allocated to a bookkeeping account (a Cash Balance Account) for each participant. The pay credits range from 3% to 8% of eligible compensation. Non-represented and UA-represented employees hired on or after January 1, 2014, and IBEW-represented employees hired on or after December 12, 2014, will receive pay credits equal to 4% (rather than the age-based pay credit described above), which non-represented and IBEW-represented employees may choose to have contributed to the Company's 401(k) plan, rather than credited under the Retirement Plan. Eligible compensation generally includes base salary and bonuses (other than bonuses paid under the LTI Plan and signing, retention and similar bonuses), up to the limit imposed by the Internal Revenue Code. For 2022, the limit was $305,000. For 2023, the limit is $330,000. In addition, as of March 1, 1997, the Cash Balance Account of each participant who was participating in the Retirement Plan on March 1, 1997, was credited with an amount based on the actuarial present value of that participant's accrued benefit, as of February 28, 1997, under the Retirement Plan's previous formula. Amounts in the Cash Balance Accounts are also credited with interest. The interest crediting rate is 4% per year or such higher amount as PSE may determine. For 2022 and 2023, the annual interest crediting rate was 4%.

A participant's Retirement Plan benefit generally vests upon the earlier of the participant's completion of three years of active service with Puget Energy, PSE or their affiliates or attainment of age 65 (the Retirement Plan's normal retirement age) while employed by the Company or one of its affiliates. Normal retirement benefit payments begin to a vested participant as of the first day of the month following the later of the participant's termination of employment or attainment of age 65 (employees designated as casual employees by PSE and who have reached age 65 or employees who have applied for long-term disability and have reached age 65 may commence benefits without terminating employment). However, a vested participant may elect to have his or her benefit under the Retirement Plan paid, or commence to be paid, as of the first day of any month commencing after the date on which his or her employment with Puget Energy, PSE and their affiliates terminates. If benefit payments commence prior to the participant's attainment of age 65, then the amount of the monthly payments will be reduced for early commencement to reflect the fact that payments will be made over a longer period of time. This reduction is subsidized - that is, it is less than a pure actuarial reduction. The amount of this reduction is, on average, 0.30% for each of the first 60 months, 0.33% for each of the second 60 months, 0.23% for each of the third 60 months and 0.17% for each of the fourth 60 months that the payment commencement date precedes the participant's 65th birthday. Further reductions apply for each additional month that the payment commencement date precedes the participant's 65th birthday. As of December 31, 2022, all the Named Executive Officers, except Ms. Kipp, Mr. Hasan and Mr. Smith were vested in their benefits under the Retirement Plan and, hence, would be eligible to commence benefit payments upon termination.

The normal form of benefit payment for unmarried participants is a straight life annuity providing monthly payments for the remainder of the participant's life, with no death benefits. The straight life annuity payable on or after the participant's normal retirement age is actuarially equivalent to the balance in the participant's Cash Balance Account as of the date of distribution. For married participants, the normal form of benefit payment is an actuarially equivalent joint and 50% survivor annuity with a "pop-up" feature providing reduced monthly payments (as compared to the straight life annuity) for the remainder of the participant's life and, upon the participant's death, monthly payments to the participant's surviving spouse for the remainder of the spouse's life in an amount equal to 50% of the amount being paid to the participant. Under the pop-up feature, if the participant's spouse predeceases the participant, the participant's monthly payments increase to the level that would have been provided under the straight life annuity. In addition, the Retirement Plan provides several other annuity payment options and a lump sum payment option that can be elected by participants. All payment options are actuarially equivalent to the straight life annuity. However, in no event will the amount of the lump sum payment be less than the balance in the participant's Cash Balance Account as of the date of distribution (in some instances the amount of the lump sum

distribution may be greater than the balance in the Cash Balance Account due to differences in the mortality table and interest rates used to calculate actuarial equivalency).

If a vested participant dies before his or her Retirement Plan benefit is paid, or commences to be paid, then the participant's Retirement Plan benefit will be paid to his or her beneficiary(ies). If a participant dies after his or her Retirement Plan benefit has commenced to be paid, then any death benefit will be governed by the form of payment elected by the participant.

Supplemental Executive Retirement Plan

The SERP provides a benefit to participating Named Executive Officers that supplements the retirement income provided to the executives by the Retirement Plan. The Company closed the SERP plan to new participants as of August 1, 2019, but existing officer participants continue to accrue benefits in the plan. All the Named Executive Officers hired (or promoted to officer) prior to 2019 participate in the SERP. A participating Named Executive Officer's SERP benefit generally vests upon the executive's completion of five years of participation in the SERP and attainment of age 55 while employed by the Company or any of its affiliates. However, SERP participants as of December 31, 2012 who have not yet attained age 55, have been exempted from the age 55 vesting requirement. All the participating Named Executive Officers with SERP eligibility are vested in their SERP benefits.

The monthly benefit payable under the SERP to a Named Executive Officer (calculated in the form of a straight life annuity payable for the executive's lifetime commencing at the later of the executive's date of termination or attainment of age 62) is equal to (i) below minus the sum of (ii) and (iii) below:

i. One-twelfth (1/12) of the executive's highest average earnings times the executive's years of credited service (not in excess of 15) times 3-1/3%. For purposes of the SERP, "highest average earnings" means the average of the executive's highest three consecutive calendar years of earnings. The three consecutive calendar years must be among the last ten calendar years completed by the executive prior to his or her termination. Prior to December 31, 2012, a participant's highest average earnings was not required to be calculated based on a three consecutive year basis. Executives participating in the SERP as of December 31, 2012 will have their highest average earnings on that date preserved as a minimum value for highest average earnings in the future. "Earnings" for this purpose include base salary and annual bonus, but do not include long-term incentive compensation. An executive will receive one "year of credited service" for each consecutive 12-month period he or she is employed by the Company or its affiliates. If an executive becomes entitled to disability benefits under PSE's long-term disability plan, then the executive's highest average earnings will be determined as of the date the executive became disabled, but the executive will continue to accrue years of credited service until he or she begins to receive SERP benefits.

ii. The monthly amount payable (or that would be payable) under the Retirement Plan to the executive in the form of a straight life annuity commencing as of the first day of the month following the later of the executive's date of termination or attainment of age 62, including amounts previously paid or segregated pursuant to a qualified domestic relations order.

iii. The actuarially equivalent monthly amount payable (or that would be payable) to the executive as of the first day of the month following the later of the executive's date of termination or attainment of age 62 from any pension-type rollover accounts within the Deferred Compensation Plan (including the annual cash balance restoration account). These accounts are described in more detail in the "2022 Nonqualified Deferred Compensation" section.

Normal retirement benefits under the SERP generally are paid or commence to be paid within 90 days following the later of the Named Executive Officer's termination of employment or attainment of age 62. Except as provided below, SERP benefits are normally paid in a lump sum that is equal to the actuarial present value of the monthly straight life annuity benefit. In lieu of the normal form of payment, an executive may elect to receive his or her SERP benefit in the form of monthly installment payments over a period of two to 20 years, in a straight life annuity or in a joint and survivor annuity with a 100%, 75%, 50% or 25% survivor benefit. All payment options are actuarially equivalent to the straight life annuity. An executive may also elect to have his or her SERP benefit transferred to the Deferred Compensation Plan and paid in accordance with his or her elections under that plan.

An executive may elect to have his or her SERP benefit paid, or commence to be paid, upon termination of employment after attaining age 55 but prior to attaining age 62. The SERP benefit of any executive who receives such early retirement benefits will be reduced by 1/3% for each month that the early commencement date precedes the beginning of the month coincident with or next following the date on which the executive attains age 62.

If a participating Named Executive Officer dies while employed by Puget Energy, PSE or any of their affiliates or after becoming vested in his or her SERP benefit, but before his or her SERP benefit has commenced to be paid, then the executive's surviving spouse will receive a lump sum benefit equal to the actuarial equivalent of the survivor benefit such spouse would have received under the joint and 50% survivor annuity option. This amount will be calculated assuming the executive would have commenced benefit payments in that form on the first day of the month following the later of his or her death or attainment of age 62, with any applicable reductions for early commencement if the executive dies before age 62. If the executive is not married, then no death benefit will be paid. If an executive dies after his or her SERP benefit has commenced to be paid, then any death benefit will be governed by the form of payment elected by the executive.

Officer Restoration Benefit

The Officer Restoration Benefit provides a benefit to participating officers that supplements the retirement income provided to the executives. Executives participating in the SERP are not eligible for this benefit. Ms. Kipp, Mr. Hasan and Mr. Smith participate in the benefit and those Company contributions under PSE's applicable tax-qualified plan that would otherwise have been earned, if not for IRS limitations, are credited by the Company to an account for each within the Deferred Compensation Plan.

2022 Nonqualified Deferred Compensation

The following table provides information for each of the Named Executive Officers regarding aggregate executive and Company contributions and aggregate earnings for 2022 and year-end account balances under the Deferred Compensation Plan.

Name	Executive Contributions in 2022[1]	Registrant Contributions in 2022[2]	Aggregate Earnings in 2022[3]	Aggregate Withdrawals/ Distributions	Aggregate Balance at December 31, 2022[4]
Mary E. Kipp	$ 1,016,624	$ 45,056	$ —	$ —	$ 2,370,392
Kazi Hasan	46,452	22,428	—	—	66,433
Allan (Wade) Smith	—	—	—	—	—
Margaret F. Hopkins	30,028	19,380	—	—	871,753
Andrew Wappler	—	—	—	—	—
Steve R. Secrist	31,058	23,167	—	(292,308)	133,943

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1. *The amount in this column reflects elective deferrals by the executive of salary, annual incentive compensation or LTI Plan awards paid in 2022. Deferred salary amounts are: Ms. Kipp, $0; Mr. Hasan, $46,452; Mr. Smith, $0; Ms. Hopkins, $30,028; Mr. Wappler, $0; and Mr. Secrist, $30,889. Deferred annual incentive compensation and LTI Plan award amounts are $0 for all Named Executives, except for Ms. Kipp who deferred $172,524 in incentive compensation and $844,100 in LTI Plan awards and Mr. Secrist who deferred $169 in annual incentive compensation.. The amounts are also included in the applicable column of the Summary Compensation Table for 2022.*
2. *The amount reported in this column reflects contributions by PSE consisting of the annual investment plan restoration amount and annual cash balance restoration amount described below. These amounts are also included in the total amounts shown in the All Other Compensation column of the Summary Compensation Table for 2022.*
3. *The amount in this column for each executive reflects the change in value of investment tracking funds. Amounts of zero indicate no change in value or a decrease in value. None of the executives received above market earnings on these amounts.*
4. *Of the amounts in this column, the amounts in the table below have also been reported in the Summary Compensation Table for 2022, 2021, and 2020.*

Name	Reported for 2022	Reported for 2021	Reported for 2020
Mary E. Kipp	$ 1,016,624	$ 1,084,486	$ 242,609
Kazi Hasan	46,452	2,125	—
Allan (Wade) Smith	—	—	—
Margaret F. Hopkins	30,028	138,978	156,861
Andrew Wappler	—	—	—
Steve R. Secrist	31,058	32,883	61,665

Deferred Compensation Plan

The Named Executive Officers are eligible to participate in the Deferred Compensation Plan and may defer up to 100% of base salary, annual incentive compensation and LTI Plan payments. In addition, each year, executives are eligible to receive Company contributions under the Deferred Compensation Plan to restore benefits not available to them under the Company's tax-qualified plans due to limitations imposed by the Internal Revenue Code. The annual investment plan restoration amount equals the additional matching and any other employer contribution under the 401(k) plan that would have been credited to an electing executive's 401(k) plan account if the Internal Revenue Code limitations were not in place and if deferrals under the Deferred Compensation Plan were instead made to the 401(k) plan. The annual cash balance restoration amount equals the actuarial equivalent of any reductions in an executive's accrued benefit under the Retirement Plan due to Internal Revenue Code limitations or as a result of deferrals under the Deferred Compensation Plan. An executive must generally be employed on the last day of the year to receive these Company contributions, unless he or she retires or dies during the year in which case the Company will contribute a prorated amount.

The Named Executive Officers choose how to credit deferred amounts among three investment tracking funds. The tracking funds mirror performance in major asset classes of bonds, stocks, and a money market index. For participants with deferrals prior to 2012, an interest crediting fund was available; however this does not apply to any of 2022's Named Executive Officers. The tracking funds differ from the investment funds offered in the 401(k) plan. The 2022 calendar year returns of these tracking funds were:

Vanguard Total Bond Market Index	(13.15)%
Vanguard 500 Index	(18.15)
Vanguard Money Market Index	1.55

The Named Executive Officers may change how deferrals are allocated to the tracking funds at any time. Changes generally become effective as of the first trading day of the following calendar quarter.

The Named Executive Officers generally may choose how and when to receive payments under the Deferred Compensation Plan from available alternatives. There are three types of in-service withdrawals. First, an executive may choose an interim payment of deferred amounts by designating a plan year for payment at the time of his or her deferral election. The interim payment is made in a lump sum within 60 days after the last day of the designated plan year, which must be at least two years following the plan year of the deferral. Second, an in-service withdrawal may also be made to an executive upon a qualifying hardship event and demonstrated need. Third, only with respect to amounts deferred and vested prior to 2005, the executive may elect an in-service withdrawal for any reason by paying a 10% penalty. Payments upon termination of employment depend on whether the executive is then eligible for retirement. If the executive's termination occurs prior to his or her retirement date (generally the earlier of attaining age 62 or age 55 with five years of credited service), the executive will receive a lump sum payment of his or her account balance. If the executive's termination occurs after his or her retirement date, the executive may choose to receive payments in a lump sum or via one of several installment options (fixed amount, specified amount, annual or monthly installments, of up to 20 years).

Potential Payments upon Termination or Change in Control

The Estimated Potential Incremental Payments Upon Termination or Change in Control table below reflects the estimated amount of incremental compensation payable to each of the Named Executive Officers in the event of (i) a change in control; (ii) an involuntary termination without cause or for good reason in connection with a change in control; (iii) retirement; (iv) disability; or (v) death.

Certain Company benefit plans provide incremental benefits or payments in the event of certain terminations of employment. The only benefit payable to the Named Executive Officers solely upon a change in control is accelerated vesting of LTI Plan awards, under certain conditions, as described below.

Disability and Life Insurance Plans

If a Named Executive Officer's employment terminates due to disability or death, the executive or his or her estate will receive benefits under the PSE disability plan or life insurance plan available generally to all salaried employees. These disability and life insurance amounts are not reflected in the table below. The Named Executive Officer is also eligible to receive supplemental disability and life insurance. The supplemental monthly disability coverage is 65% of monthly base salary and target annual incentive pay, reduced by (i) amounts receivable under the PSE disability plan generally available to salaried employees and (ii) certain other income benefits. The supplemental life insurance benefit is provided at two times base salary and target annual incentive bonus if the executive dies while employed by PSE with a reduction for amounts payable under the applicable group life insurance policy.

LTI Plan Awards

If a Named Executive Officer's employment terminates due to disability or death, the executive or his or her estate will be paid a pro-rata portion of LTI Plan awards that were granted in a prior year. In the case of retirement at normal retirement age or approved early retirement, pro-rata LTI Plan awards will be paid in the first quarter following the year of retirement, based on performance through the prior year. In the event of a change in control in which awards are not assumed or substituted,

outstanding LTI Plan awards will be paid on a pro-rata basis at the higher of (i) target performance or (ii) actual performance achieved during the performance cycle ending with the fiscal quarter that precedes the change in control.

Employment Agreements

PSE has no employment agreements with any executive officers, including the Named Executive Officers.

Estimated Potential Incremental Payments upon Termination or Change in Control

The amounts shown in the table below assume that the termination of employment of a Named Executive Officer or a change in control was effective as of December 31, 2022. The amounts below are estimates of the incremental amounts that would be paid out to the Named Executive Officer upon a termination of employment or a change in control. Actual amounts payable can only be determined at the time of a termination of employment or a change in control. Mr. Secrist was not employed as of as of December 31, 2022 and is not included in the table. The pro-rated LTI Plan amounts payable to him in connection with his retirement pursuant to the terms of the LTI Plan are disclosed in the "Details of All Other Compensation" section of the Summary Compensation Table, which aggregate amount was $873,290.

	Upon Change in Control (and awards not assumed or substituted)	After Change in Control Involuntary Termination w/o Cause or for Good Reason	Retirement	Disability	Death
Mary E. Kipp	$ —	$ —	$ —	$ —	$ —
Long Term Incentive Plan	5,313,294	5,313,294	—	4,885,438	4,885,438
Supplemental Life Insurance	—	—	—	—	3,885,975
Total Estimated Incremental Value	$ 5,313,294	$ 5,313,294	$ —	$ 4,885,438	$ 8,771,413
Kazi Hasan	$ —	$ —	$ —	$ —	$ —
Long Term Incentive Plan	1,207,500	1,207,500	—	1,054,103	1,053,103
Supplemental Life Insurance	—	—	—	—	1,482,806
Total Estimated Incremental Value	$ 1,207,500	$ 1,207,500	$ —	$ 1,054,103	$ 2,535,909
Allan (Wade) Smith	$ —	$ —	$ —	$ —	$ —
Long Term Incentive Plan	1,048,950	1,048,950	—	808,419	808419
Supplemental Life Insurance	—	—	—	—	1,668,000
Total Estimated Incremental Value	$ 1,048,950	$ 1,048,950	$ —	$ 808,419	$ 2,476,419
Margaret F. Hopkins	$ —	$ —	$ —	$ —	$ —
Long Term Incentive Plan	690,318	690,318	—	626,529	626,529
Supplemental Life Insurance	—	—	—	—	980,911
Total Estimated Incremental Value	$ 690,318	$ 690,318	$ —	$ 626,529	$ 1,607,440
Andrew Wappler	$ —	$ —	$ —	$ —	$ —
Long Term Incentive Plan	411,328	411,328	—	375,219	375,219
Supplemental Life Insurance	—	—	—	—	924,683
Total Estimated Incremental Value	$ 411,328	$ 411,328	$ —	$ 375,219	$ 1,299,902

Chief Executive Officer Pay Ratio

We are providing the following information about the relationship of the annual total compensation of our employees and the annual total compensation for our Chief Executive Officer in accordance with SEC Item 402(u) of Regulation S-K.

For 2022, our last completed fiscal year:

- The annual total compensation of our CEO reported in the 2022 Summary Compensation Table, was $4,760,931.
- The median of the annual total compensation of all our employees (excluding our CEO) was $126,400.

As a result, for 2022 the ratio of annual total compensation of our Chief Executive Officer to the median of our annual total compensation of all employees was 38:1.

We identified our median employee by examining the total cash compensation we paid during 2022 to all individuals, excluding our CEO, who were employed by us on December 31, 2022, which totaled approximately 3,250 individuals, all located in the United States (as reported in Item 1. Business), including employees, whether employed on a full-time, part-time or seasonal basis. Total cash compensation consisted of base salary, overtime, paid time off and annual incentives as reflected in our payroll records. We consistently applied this compensation measure and did not make any assumptions, adjustments, or estimates with respect to total cash compensation. We believe that the use of total cash compensation for all employees is a consistently applied compensation measure because it includes all major compensation elements available to employees.

After identifying the median employee based on total cash compensation for 2022, we calculated annual total compensation for such employee for 2022 using the same methodology we use for our named executive officers as set forth in the 2022 Summary Compensation Table in accordance with the requirements of Item 402 (c)(2)(x) of Regulation S-K. Annual total compensation for 2022 for our median employee included annual salary, annual incentives, and company contributions towards benefits including retirement. Annual total compensation for 2022 for our CEO consists of the amount reported in the "Total" column of our 2022 Summary Compensation Table.

Director Compensation for Fiscal Year 2022

The following table sets forth information regarding compensation paid by the Company to the directors named in the table who received compensation from the Company in 2022 for service as directors. We refer to these directors as non-employee directors. Directors who are employed by the Company or by the Company's investor-owners are not paid separately for their service and thus are not named in the table below. The directors who are employed by the Company's investor-owners are: Grant Hodgkins, Jean-Paul Marmoreo, Chris Parker, Aaron Rubin, Martijn Verwoest, and Steven Zucchet.

As described in further detail below, the Company's non-employee director compensation program in 2022 consisted of quarterly retainer cash fees of $42,500. Additional quarterly retainer amounts associated with serving as Chair of the Board, chairing Board committees, serving on the Audit Committee and meeting fees were also paid in cash.

Name	Fees Earned	Nonqualified Deferred Compensation Earnings[1]	Total
Scott Armstrong	$ 235,534	$ —	$ 235,534
Richard Dinneny	177,200	—	177,200
Barbara Gordon	192,200	—	192,200
Thomas King	177,200	—	177,200
Paul McMillan	188,200	—	188,200
Diana Rakow	114,000	—	114,000

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1. *Represents earnings accrued on deferred compensation considered to be above market.*

Non-employee Director Compensation Program

The 2022 non-employee director compensation program is based on the principles that the level of non-employee director compensation should be based on Board and committee responsibilities and should be competitive with comparable companies.

The 2022 compensation program for non-employee directors was as follows:

1. A base cash quarterly retainer fee of $42,500;
2. A $1,600 per meeting fee ($800 for telephonic) will be paid when the number of Board or Committee meetings exceed six per year (not applicable to Asset Management Committee calls).

In 2022, non-employee directors were paid the following additional cash quarterly retainer fees:

1. Independent Board Chairman, $13,750;
2. Chair of the Compensation and Leadership Development Committee, $3,750;
3. Chair of the Governance Committee, $3,750;
4. Chair of the Business Planning Committee, $3,750
5. Chair of the Audit Committee, $3,750; and
6. Each member of the Audit Committee other than the chair, $1,000.

Non-employee directors were reimbursed for actual travel and out-of-pocket expenses incurred in connection with their services. Non-employee directors are eligible to participate in the Company's matching gift program on the same terms as all Puget Energy employees. Under this program, the Company matches up to a total of $500 a year in contributions by a director to non-profit organizations that have Internal Revenue Service (IRS) 501(c)(3) tax exempt status and are located in and served the people of PSE's service territory in Washington State.

Deferral of Compensation

Non-employee directors may choose to elect to defer all or a part of their cash fees under the Company's Deferred Compensation Plan for non-employee directors. Non-employee directors may allocate these deferrals into one or more "measurement funds," which include an interest crediting fund, an equity index fund and a bond index fund. Non-employee directors are permitted to make changes in measurement fund allocations quarterly.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED SHAREHOLDER MATTERS

Security Ownership of Directors, Executive Officers and Certain Beneficial Owners

The following tables show the number of shares of common stock beneficially owned as of December 31, 2022, by each person or group that we know owns more than 5.0% of Puget Energy's and PSE's common stock. No director, executive officer or executive officer named in the Summary Compensation Table in Item 11 of Part III of this report owns any of the outstanding shares of common stock of Puget Energy or PSE. Puget Equico LLC (Puget Equico) and its affiliates beneficially own 100.0% of the outstanding common stock of Puget Energy. Puget Energy holds 100.0% of the outstanding common stock of PSE. Percentage of beneficial ownership is based on 200 shares of Puget Energy common stock and 85,903,791 shares of PSE common stock outstanding as of February 23, 2023.

Beneficial Ownership Table of Puget Energy and PSE

	Number of Beneficially Owned Shares	
Name	Puget Energy	Puget Sound Energy
Puget Equico LLC and affiliates	200[1, 2]	—
Puget Energy	—	85,903,791[3]

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1 *Information presented above and in this footnote is based on Amendment No. 2 to Schedule 13D/A filed on February 13, 2009 (the Schedule 13D) by, among others, Puget Equico, Puget Intermediate Holdings Inc. (Puget Intermediate), Puget Holdings LLC (Puget Holdings and together with Puget Intermediate, the Parent Entities), 6860141 Canada Inc. as trustee for British Columbia Investment Management Corporation (BCI), PIP2PX (Pad) Ltd. (PIP2PX) and PIP2GV (Pad) Ltd. ((PIP2GV), and together with Clean Energy JV Sub 1, LP (JV Sub 1), Clean Energy JV Sub 2, LP (JV Sub 2), Ontario Municipal Employee Retirement System (OMERS), PGGM Vermogensbeheer B.V. (PGGM), BCI and PIP2PX, the Investors). Puget Equico is a wholly-owned subsidiary of Puget Intermediate, Puget Intermediate is a wholly-owned subsidiary of Puget Holdings and the Investors are the direct or indirect owners of Puget Holdings. The Parent Entities and the Investors are the direct or indirect owners of Puget Equico. Although the Parent Entities and the Investors do not own any shares of Puget Energy directly, Puget Equico, the Parent Entities and the Investors may be deemed to be members of a "group," within the meaning of Section 13(d)(3) of the Securities Exchange Act of 1934, as amended. Accordingly, each such entity may be deemed to beneficially own the 200 shares of Puget Energy common stock owned by Puget Equico. Such shares of common stock constitute 100.0% of the issued and outstanding shares of common stock of Puget Energy. Under Section 13(d)(3) of the Exchange Act and based on the number of shares outstanding, Puget Equico, the Parent Entities and the Investors may be deemed to have shared power to vote and shared power to dispose of such shares of Puget Energy common stock that may be beneficially owned by Puget Equico. However, each of Puget Equico, the Parent Entities and the Investors expressly disclaims beneficial ownership of such shares of common stock other than those shares held directly by such entity. As of February 23, 2023:*

- *The address of the principal office of Puget Holdings, Puget Intermediate and Puget Equico is the PSE Building, 355 110th Ave NE, Bellevue, WA 98004.*
- *The address of the principal office of OMERS is 900-100 Adelaide Street West, Toronto, Ontario, Canada, M5H E02.*
- *The address of the principal office of PGGM is Noordweg Noord 150, 3704 JG Zeist, Netherlands.*
- *The address of the principal office of JV Sub 1 is 125 West 55th Street, Level 15 New York, NY 10019.*
- *The address of the principal office of JV Sub 2 is 5650 Yonge Street Toronto, Ontario, M2M 4H5 Canada.*
- *The address of the principal office of BCI is 750 Pandora Ave, Victoria, British Columbia, Canada V8W 0E4.*
- *The address of the principal office of PIP2PX and PIP2GV is 10250, 101 Street NW, Edmonton, Alberta, Canada T5J 3P4.*

2 *Pursuant to that certain Pledge Agreement dated as of May 10, 2010, as amended on February 10, 2012, and as further amended and extended as of April 15, 2014, made by Puget Equico to JPMorgan Chase Bank, N.A., as administrative agent, the outstanding stock of Puget Energy held by Puget Equico was pledged by Puget Equico to secure the obligations of Puget Energy under (a) the Credit Agreement dated as of February 10, 2012, as amended and extended April 15, 2014, among Puget Energy, JPMorgan Chase Bank, N.A., as administrative agent, the other agents party thereto, which Credit Agreement was amended and restated by the Second Amended and Restated Credit Agreement dated May 16, 2022 among Puget Energy, Inc. as Borrower, JP Morgan Chase Bank N.A. as Administrative Agent, and the lenders party thereto and (b) the senior secured notes issued on May 12, 2015, May 19, 2020, June 14, 2020, and March 17, 2022.*

3 *Pursuant to that certain Borrower's Security Agreement dated as of May 10, 2010, as amended on February 10, 2012, and as further amended and extended as of April 15, 2014, the outstanding stock of PSE held by Puget Energy was pledged by Puget Energy to secure its obligations under (a) the Credit Agreement dated as of February 10, 2012, as amended and extended April 15, 2014, among Puget Energy as Borrower, JPMorgan Chase Bank, N.A., as administrative agent, the other agents party thereto, and the lenders party thereto, which Credit Agreement was amended and restated by the Second Amended and Restated Credit Agreement dated May 16, 2022 among Puget Energy Inc., as Borrower, JPMorgan Chase Bank N.A., as Administrative Agent, and the lenders party thereto and (b) the senior secured notes issued on December 6, 2010, June 3, 2011May 12, 2015, May 19, 2020, June 1514, 20122020 and May 12, 2015March 17, 2022.*

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR

Transactions with Related Persons

Our Boards of Directors have adopted a written policy for the review and approval or ratification of related person transactions. Under the policy, our directors and executive officers are expected to disclose to our Chief Compliance Officer the material facts of any transaction that could be considered a related person transaction promptly upon gaining knowledge of the transaction. A related person transaction is generally defined as any transaction required to be disclosed under Item 404(a) of Regulation S-K, the SEC's related person transaction disclosure rule.

Any transaction reported to the Chief Compliance Officer will be reviewed according to the following procedures:

1. If the Chief Compliance Officer determines that disclosure of the transaction is not required under the SEC's related person transaction disclosure rule, the transaction will be deemed approved and will be reported to the Audit Committee.
2. If disclosure is required, the Chief Compliance Officer will submit the transaction to the Chair of the Audit Committee who will review and, if authorized, will determine whether to approve or ratify the transaction. The Chair is authorized to approve or ratify any related person transaction involving an aggregate amount of less than $1.0 million or when it would be impracticable to wait for the next Audit Committee meeting to review the transaction.
3. If the transaction is outside the Chair's authority, the Chair will submit the transaction to the Audit Committee for review and approval or ratification.

When determining whether to approve or ratify a related person transaction, the Chair of the Audit Committee or the Audit Committee, as applicable, will review relevant facts regarding the related person transaction, including:

1. The extent of the related person's interest in the transaction;
2. Whether the terms are comparable to those generally available in arm's length transactions; and
3. Whether the related person transaction is consistent with the best interests of the Company.

If any related person transaction is not approved or ratified, the Committee may take such action as it may deem necessary or desirable in the best interests of the Company and its shareholders.

Board of Directors and Corporate Governance

Independence of the Board

The Boards of Puget Energy and PSE have reviewed the relationships between Puget Energy and PSE (and their respective subsidiaries) and each of their respective directors. Based on this review, the Boards have determined that of the members constituting the Boards, Scott Armstrong and Barbara Gordon (members of the Boards of both Puget Energy and PSE) and Diana Rakow (member of the Board of PSE) are independent under the NYSE corporate governance listing standards and also meet the definition of an "Independent Director" under the Company's Amended and Restated Bylaws. Under the Amended and Restated Bylaws of Puget Energy and PSE, an Independent Director is a director who: (i) shall not be a member of Puget Holdings (referred to as a Holdings Member) or an affiliate of any Holdings Member (including by way of being a member, stockholder, director, manager, partner, officer or employee of any such member), (ii) shall not be an officer or employee of PSE, (iii) shall be a resident of the state of Washington, and (iv) if and to the extent required with respect to any specific director, shall meet such other qualifications as may be required by any applicable regulatory authority for an independent director or manager. The Company's definition of "Independent Director" is available in the Corporate Governance Guidelines at www.pugetenergy.com.

In making these independence determinations, the Boards have established a categorical standard that a director's independence is not impaired solely as a result of the director, or a company for which the director or an immediate family member of the director serves as an executive officer, making payments to PSE for power or natural gas provided by PSE at rates fixed in conformity with law or governmental authority, unless such payments would automatically disqualify the director under the NYSE's corporate governance listing standards. The Boards have also established a categorical standard that a director's independence is not impaired if a director is a director, employee or executive officer of another company that makes payments to or receives payments from Puget Energy, PSE or any of their affiliates, for property or services in an amount

which is less than the greater of $1.0 million or one percent of such other company's consolidated gross revenue, determined for the most recent fiscal year. These categorical standards will not apply, however, to the extent that Puget Energy or PSE would be required to disclose an arrangement as a related person transaction pursuant to Item 404 of Regulation S-K.

The Boards considered all relationships between its directors and Puget Energy and PSE (and their respective subsidiaries), including some that are not required to be disclosed in this report as related-person transactions. Mr. Armstrong and Ms. Rakow serve (or served) as directors or officers of, or otherwise have/had a financial interest in entities that make payments to PSE for energy services provided to those entities at tariff rates established by the Washington Commission. These transactions fall within the first categorical independence standard described above. Because these relationships either fall within the Boards' categorical independence standards or involve an amount that is not material to the Company or the other entity, the Boards have concluded that none of these relationships, in isolation, impair the independence of the applicable directors.

Executive Sessions

Non-management directors meet in executive session on a regular basis, generally on the same date as each scheduled Board meeting. Mr. Armstrong, who is not a member of management, presides over the executive sessions. Interested parties may communicate with the non-management directors of the Board through the procedures described in Item 10, "Directors, Executives Officers and Corporate Governance" of Part III of this Form 10-K under the section "Communications with the Board."

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The aggregate fees billed by PricewaterhouseCoopers LLP (PCAOB ID No. 238), the Company's independent registered public accounting firm, for the years ended December 31, 2022, and 2021 were as follows:

	2022		2021	
(Dollars in Thousands)	Puget Energy	PSE	Puget Energy	PSE
Audit fees[1]	$ 2,881	$ 2,611	$ 2,547	$ 2,299
Audit related fees[2]	239	43	308	80
Other fees[3]	60	60	54	54
Total	$ 3,180	$ 2,714	$ 2,909	$ 2,433

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1. *For professional services rendered for the audit of Puget Energy's and PSE's annual financial statements and reviews of financial statements included in the Company's Forms 10-Q. The 2022 fees are estimated and include an aggregate amount of $2.2 million billed to Puget Energy and $1.8 million billed to PSE through December 2022.*

2. *Consists of work performed in connection with registration statements and other regulatory audits. Audit related fees for Puget Energy contain amounts related to the PLNG Assess and Recommend procedures.*

3. *Consists of software and research tools.*

The Audit Committee of the Company has adopted policies for the pre-approval of all audit and non-audit services provided by the Company's independent registered public accounting firm. The policies are designed to ensure that the provision of these services does not impair the firm's independence. Under the policies, unless a type of service to be provided by the independent registered public accounting firm has received general pre-approval, it will require specific pre-approval by the Audit Committee. In addition, any proposed services exceeding pre-approved cost levels will require specific pre-approval by the Audit Committee.

The annual audit services engagement terms and fees, as well as any changes in terms, conditions and fees relating to the engagement, are subject to specific pre-approval by the Audit Committee. In addition, on an annual basis, the Audit Committee grants general pre-approval for specific categories of audit, audit-related, tax and other services, within specified fee levels, that may be provided by the independent registered public accounting firm. With respect to each proposed pre-approved service, the independent registered public accounting firm is required to provide detailed back-up documentation to the Audit Committee regarding the specific services to be provided. Under the policies, the Audit Committee may delegate pre-approval authority to one or more of their members. The member or members to whom such authority is delegated shall report any pre-approval decision to the Audit Committee at its next scheduled meeting. The Audit Committee does not delegate responsibilities to pre-approve services performed by the independent registered public accounting firm to management. For 2022 and 2021, all audit and non-audit services were pre-approved.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

a) Documents filed as part of this report:

1) Financial Statements

2) Financial Statement Schedules. Financial Statement Schedules of the Company, as required for the years ended December 31, 2022, 2021, and 2020, consist of the following:

I. Condensed Financial Information of Puget Energy

II. Valuation of Qualifying Accounts and Reserves

3) Exhibits

ITEM 16. FORM 10-K SUMMARY

None.

EXHIBIT INDEX

Certain of the following exhibits are filed herewith. Certain other of the following exhibits have heretofore been filed with the SEC and are incorporated herein by reference.

	3.1	Amended Articles of Incorporation of Puget Energy (incorporated herein by reference to Exhibit 3.1 to Puget Energy's Current Report on Form 8-K, dated February 6, 2009, Commission File No. 1-16305).
	3.2	Amended and Restated Articles of Incorporation of Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit 3.2 to Puget Sound Energy's Current Report on Form 8-K, dated February 6, 2009, Commission File No. 1-4393).
	3.3	Amended and Restated Bylaws of Puget Energy, Inc., as amended by the First Amendment to the Amended and Restated Bylaws of Puget Energy Inc., dated January 6, 2022 (incorporated herein by reference to Exhibit 3.3 to Puget Energy's Current Report on Form 10-K, dated February 25, 2022, Commission File No. 1-16305).
	3.4	Amended and Restated Bylaws of Puget Sound Energy, Inc., as amended by the First Amendment to the Amended and Restated Bylaws of Puget Sound Energy, Inc. dated January 6, 2022 (incorporated herein by reference to Exhibit 3.4 to Puget Sound Energy's Current Report on Form 10-K, dated February 25, 2022, Commission File No. 1-04393).
***	4.1	Indenture between Puget Sound Energy, Inc. and U.S. Bank National Association (as successor to State Street Bank and Trust Company) defining the rights of the holders of Puget Sound Energy's senior notes (incorporated herein by reference to Exhibit 4-a to Puget Sound Energy's Quarterly Report on Form 10-Q for the quarter ended June 30, 1998, Commission File No. 1-4393).
	4.2	First, Second, Third, Fourth, and Fifth Supplemental Indentures defining the rights of the holders of Puget Sound Energy's senior notes (incorporated herein by reference to Exhibit 4-b to Puget Sound Energy's Quarterly Report on Form 10-Q for the quarter ended June 30, 1998 (Exhibit originally filed with the Securities and Exchange Commission in paper format and as such, a hyperlink is not available.), Commission File No. 1-4393; Exhibit 4.26 to Puget Sound Energy's Current Report on Form 8-K, dated March 4, 1999 (Exhibit originally filed with the Securities and Exchange Commission in paper format and as such, a hyperlink is not available.), Commission File No. 1-4393; Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated November 2, 2000 (Exhibit originally filed with the Securities and Exchange Commission in paper format and as such, a hyperlink is not available.), Commission File No. 1-4393; Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated May 28, 2003, Commission File No. 1-4393 and Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated May 23, 2018, Commission File No. 1-4393.)
	4.3	Fortieth through Sixtieth Supplemental Indentures defining the rights of the holders of Puget Sound Energy's Electric Utility First Mortgage Bond (incorporated herein by reference to Puget Sound Energy's Registration Statement on Form S-3, filed March 13, 2009, Registration No. 333-157960). Exhibits 4.3 through and including 4.23: 4.3, 4.4, 4.5, 4.6, 4.7, 4.8, 4.9. 4.10, 4.11, 4.12, 4.13, 4.14, 4.15, 4.16, 4.17, 4.18, 4.19, 4.20, 4.21, 4.22, 4.23.
***	4.4	Sixty-first through Eighty-seventh Supplemental Indentures defining the rights of the holders of Puget Sound Energy's Electric Utility First Mortgage Bonds (incorporated herein by reference to Exhibit (4)-j-1 to Registration No. 2-72061; Exhibit (4)-a to Registration No. 2-91516; Exhibit (4)-b to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 1985, (Exhibit originally filed with Securities and Exchange Commission File No. 1-4393; Exhibits (4)(a) and (4)(b) to Puget Sound Energy's Current Report on Form 8-K, dated April 22, 1986, Commission File No. 1-4393; Exhibit (4)(b) to Puget Sound Energy's Current Report on Form 8-K, dated September 5, 1986, not available). Commission File No. 1-4393; Exhibit (4)-b to Puget Sound Energy's Report on Form 10-Q for the quarter ended September 30, 1986, Commission File No. 1-4393; Exhibit (4)-c to Registration No. 33-18506; Exhibit (4)-b to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 1989, Commission File No. 1-4393; Exhibit (4)-b to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 1990, Commission File No. 1-4393; Exhibits (4)-d and (4)-e to Registration No. 33-45916; Exhibit (4)-c to Registration No. 33-50788; Exhibit (4)-a to Registration No. 33-53056; Exhibit 4.3 to Registration No. 33-63278; Exhibit 4-c to Puget Sound Energy's Report on Form 10-Q for the quarter ended June 20, 1998. Commission File No. 1-4393; Exhibit 4.27 to Puget Sound Energy's Current Report on Form 8-K, dated March 4, 1999. Commission File No. 1-4393; Exhibit 4.2 to Puget Energy's Current Report on Form 8-K, dated November 2, 2000. Commission File 1-4393; Exhibit 4.2 to Puget Sound Energy's Current Report on Form 8-K, dated May 28,2003 Commission File No. 1-4393; Exhibit 4.28 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2004. Commission File No. 1-4393; Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated May 23, 2005. Commission File No. 1-4393; Exhibit 4.30 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2005.
***		Commission File No. 1-4393); Exhibit 4.4 to Post-Effective Amendment No. 2 to Puget Sound Energy's Registration Statement on Form S-3, filed February 9, 2009. Registration No. 333-132497-01; Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated September 13, 2006.

***		Commission File No. 1-4393; Exhibit 4.1 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2007. Commission File No. 1-4393; and Exhibit 4.5 to Post-Effective Amendment No. 2 to Puget Sound Energy's Registration Statement on Form S-3, filed February 9, 2009. Registration No. 333-132497-01); Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated September 8, 2009, Commission File No. 1-4393. Commission File No. 1-4393; Exhibit 4.28 to Puget Sound Energy's Current Report on 10-K for fiscal year ended December 31, 2004.

4.5 Eighty-eighth, Eighty-ninth and Ninetieth Supplemental Indentures defining the rights of the holders of Puget Sound Energy's Electric Utility First Mortgage Bonds (incorporated herein by reference to Exhibits 4.1 through 4.3 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2012, Commission File No. 1-4393).

Exhibits 4.1 through 4.3: 4.1, 4.2, 4.3.

4.6 Ninety-first and Ninety-second supplemental Indentures defining the rights of the holders of Puget Sound Energy's Electric Utility First Mortgage Bonds (incorporated herein by reference to Exhibit 4.6 to Puget Sound Energy's Registration Statement on Form S-3, filed January 24, 2014, Registration No. 333-193555 and to Exhibit 4.4 to Puget Sound Energy's Current Report on Form 8-K filed May 29, 2013).

4.7 Indenture of First Mortgage, dated as of April 1, 1957, defining the rights of the holders of Puget Sound Energy's Gas Utility First Mortgage Bonds (incorporated herein by reference to Puget Sound Energy's Registration Statement on Form S-3ASR, filed March 13, 2009, Registration No. 333-157960).

4.8 First, Sixth, Seventh, Sixteenth and Seventeenth Supplemental Indenture to the Gas Utility First Mortgage, dated as of April 1, 1957, August 1, 1966, February 1, 1967, June 1, 1977, and August 9, 1978, respectively (incorporated herein by reference to Exhibits 4.26 through and including 4.30 to Puget Sound Energy's Registration Statement on Form S-3, filed March 13, 2009, Registration No. 333-157960).

Exhibits 4.26 through 4.30: 4.26, 4.27, 4.28, 4.29, 4.30.

*** 4.9 Twenty-second Supplemental Indenture to the Gas Utility First Mortgage, dated as of July 15, 1986 (incorporated herein by reference to Exhibit 4-B.20 to Washington Natural Gas Company's Annual Report on Form 10-K for the fiscal year ended September 30, 1986, Commission File No. 0-951).

*** 4.10 Twenty-seventh Supplemental Indenture to the Gas Utility First Mortgage, dated as of September 1, 1990 (incorporated herein by reference to Exhibit 4.12 to Post-Effective Amendment No. 2 to Puget Sound Energy's Registration Statement on Form S-3, filed February 9, 2009, Registration No. 333-132497-01).

*** 4.11 Twenty-eighth through Thirty-sixth Supplemental Indentures to the Gas Utility First Mortgage (incorporated herein by reference to Exhibit 4-A to Washington Natural Gas Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 1993, Commission File No. 0-951; Exhibit 4-A to Washington Natural Gas Company's Registration Statement on Form S-3, Registration No. 33-49599; Exhibit 4-A to Washington Natural Gas Company's Registration Statement on Form S-3, Registration No. 33-61859; Exhibit 4.30 to Puget Sound Energy's Annual Report on Form 10-K for the fiscal year ended December 31, 2002, Commission File No. 1-4393; Exhibits 4.22 and 4.23 to Puget Sound Energy's Annual Report on Form 10-K for the fiscal year ended December 31, 2005. Commission File No. 1-4393; Exhibits 4.22 and 4.23 to Puget Sound Energy's Annual Report on Form 10-K for the fiscal year ended December 31, 2007, Commission File No. 1-4393; and Exhibit 4.14 to Post-Effective Amendment No. 2 to Puget Sound Energy's Registration Statement on Form S-3, filed February 9, 2009, Registration No. 333-132497-01).

4.12 Unsecured Debt Indenture, dated as of May 18, 2001, between Puget Sound Energy, Inc. and The Bank of New York Mellon Trust Company, N.A. (as successor to Bank One Trust Company, N.A.) defining the rights of the holders of Puget Sound Energy's unsecured debentures (incorporated herein by reference to Exhibit 4.3 to Puget Sound Energy's Current Report on Form 8-K, dated May 18, 2001, Commission File No. 1-4393).

4.13 Second Supplemental Indenture to the Unsecured Debt Indenture, dated June 1, 2007, between Puget Sound Energy, Inc. and The Bank of New York Mellon Trust Company, N.A. defining the rights of Puget Sound Energy's Series A Enhanced Junior Subordinated Notes due June 1, 2067 (incorporated herein by reference to Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated May 30, 2007, Commission File No. 1-4393).

4.14 Third Supplemental Indenture to the Unsecured Debt Indenture, dated March 19, 2018, between Puget Sound Energy, Inc. and The Bank of New York Mellon Trust Company, N.A. defining the rights of Puget Sound Energy's Series A Enhanced Junior Subordinated Notes due June 1, 2067 (incorporated herein by reference to Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated March 26, 2018, Commission File No. 1-4393).

4.15 Form of Replacement Capital Covenant of Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit 4.2 to Puget Sound Energy's Current Report on Form 8-K, dated May 30, 2007, Commission File No. 1-4393).

4.16 Indenture and First Supplemental Indenture between Wells Fargo Bank, National Association and Puget Energy, Inc. dated as of December 6, 2010 (incorporated by reference to Exhibits 4.1 and 4.2 to Puget Energy's Current Report on Form 8-K, filed December 7, 2010, Commission File No. 1-16305).

4.17 First Supplemental Indenture to the Indenture dated December 6, 2010 between Puget Energy, Inc. and Wells Fargo Bank, National Association defining the rights of Puget Energy's Senior Secured Notes due December 15, 2020 (incorporated by reference to Exhibit 4.2 to Puget Energy's Current Report on Form 8-K, filed December 7, 2010, Commission File No. 1-16305).

4.18 Second Supplemental Indenture to the Indenture dated December 6, 2010 between Puget Energy, Inc. and Wells Fargo Bank, National Association defining the rights of Puget Energy's Senior Secured Notes due September 1, 2021 (incorporated herein by reference to Exhibit 4.1 to Puget Energy's Current Report on Form 8-K, filed June 6, 2011, Commission File No. 1-16305).

4.19 Third Supplemental Indenture between Wells Fargo Bank, National Association and Puget Energy, Inc. dated as of June 15, 2012 (incorporated by reference to Exhibits 4.1 to Puget Energy's Current Report on Form 8-K, filed June 18, 2012, Commission File No. 1-16305).

4.20 Trust Indenture, dated as of May 1, 2013 (the "Indenture"), by and between the City and Wells Fargo Bank, National Association, as trustee. (incorporated herein by reference to Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated May 30, 2013, Commission File No. 1-04393).

4.21 Loan Agreement, dated as of May 1, 2013, between Puget Sound Energy, Inc. and the City of Forsyth, Rosebud County, Montana. (incorporated herein by reference to Exhibit 4.2 to Puget Sound Energy's Current Report on Form 8-K, dated May 30, 2013, Commission File No. 1-04393).

4.22 Pledge Agreement, dated as of May 1, 2013, between Puget Sound Energy, Inc. and Wells Fargo Bank, National Association, as trustee. (incorporated herein by reference to Exhibit 4.3 to Puget Sound Energy's Current Report on Form 8-K, dated May 30, 2013, Commission File No. 1-04393).

4.23 Fourth Supplemental Indenture dated as of May 12, 2015, between Puget Energy, Inc. and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Puget Energy's Current Report on Form 8-K, dated May 13, 2015, Commission File No. 1-16305).

4.24 Fifth Supplemental Indenture dated May 19, 2020 relating to Puget Energy's 4.1% Senior Secured Notes due 2030 (Incorporated herein by reference to Exhibit 4.1 to Puget Energy's Current Report on Form 8-K Filed May 19, 2020, Commission File No. 1-16305).

4.25 Sixth Supplemental Indenture dated June 14, 2021 relating to Puget Energy's 2.379% Senior Secured Notes due 2028 (incorporated herein by reference to Exhibit 4.1 to Puget Energy's Current Report on Form 8-K Filed June 21, 2021, Commission File No. 1-16305).

4.26 Seventh Supplemental Indenture dated March 17, 2022 relating to Puget Energy's 4.224% Senior Secured Notes due 2032 (incorporated herein by reference to Exhibit 4.1 to Puget Energy's Current Report on Form 8-K Filed March 18, 2022, Commission File No. 1-16305).

*** 10.1 First Amendment dated as of October 4, 1961 to Power Sales Contract between Public Utility District No. 1 of Chelan County, Washington and Puget Sound Energy, Inc., relating to the Rocky Reach Project (incorporated herein by reference to Exhibit 10.1 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

*** 10.2 First Amendment dated February 9, 1965 to Power Sales Contract between Public Utility District No. 1 of Douglas County, Washington and Puget Sound Energy, Inc., relating to the Wells Development (incorporated herein by reference to Exhibit 10.2 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

*** 10.3 Contract dated November 14, 1957 between Public Utility District No. 1 of Chelan County, Washington and Puget Sound Energy, Inc., relating to the Rocky Reach Project (incorporated herein by reference to Exhibit 10.3 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

*** 10.4 Power Sales Contract dated as of November 14, 1957 between Public Utility District No. 1 of Chelan County, Washington and Puget Sound Energy, Inc., relating to the Rocky Reach Project (incorporated herein by reference to Exhibit 10.4 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

*** 10.5 Power Sales Contract dated May 21, 1956 between Public Utility District No. 2 of Grant County, Washington and Puget Sound Energy, Inc., relating to the Priest Rapids Project (incorporated herein by reference to Exhibit 10.5 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

*** 10.6 First Amendment to Power Sales Contract dated as of August 5, 1958 between Puget Sound Energy, Inc. and Public Utility District No. 2 of Grant County, Washington, relating to the Priest Rapids Development (incorporated herein by reference to Exhibit 10.6 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

*** 10.7 Power Sales Contract dated June 22, 1959 between Public Utility District No. 2 of Grant County, Washington and Puget Sound Energy, Inc., relating to the Wanapum Development (incorporated herein by reference to Exhibit 10.7 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

*** 10.8 Agreement to Amend Power Sales Contracts dated July 30, 1963 between Public Utility District No. 2 of Grant County, Washington and Puget Sound Energy, Inc., relating to the Wanapum Development (incorporated herein by reference to Exhibit 10.8 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

*** 10.9 Power Sales Contract executed as of September 18, 1963 between Public Utility District No. 1 of Douglas County, Washington and Puget Sound Energy, Inc., relating to the Wells Development (incorporated herein by reference to Exhibit 10.9 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

*** 10.10 Construction and Ownership Agreement dated as of July 30, 1971 between The Montana Power Company and Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit 10.10 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

*** 10.11 Operation and Maintenance Agreement dated as of July 30, 1971 between The Montana Power Company and Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit 10.11 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

*** 10.12 Contract dated June 19, 1974 between Puget Sound Energy, Inc. and P.U.D. No. 1 of Chelan County (incorporated herein by reference to Exhibit 10.12 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

*** 10.13 Transmission Agreement dated April 17, 1981 between the Bonneville Power Administration and Puget Sound Energy, Inc. (Colstrip Project) (incorporated herein by reference to Exhibit (10)-55 to Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

*** 10.14 Transmission Agreement dated April 17, 1981 between the Bonneville Power Administration and Montana Intertie Users (Colstrip Project) (incorporated herein by reference to Exhibit (10)-56 to Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

*** 10.15 Ownership and Operation Agreement dated as of May 6, 1981 between Puget Sound Energy, Inc. and other Owners of the Colstrip Project (Colstrip 3 and 4) (incorporated herein by reference to Exhibit (10)-57 to Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

*** 10.16 Colstrip Project Transmission Agreement dated as of May 6, 1981 between Puget Sound Energy, Inc. and Owners of the Colstrip Project (incorporated herein by reference to Exhibit (10)-58 to Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

*** 10.17 Common Facilities Agreement dated as of May 6, 1981 between Puget Sound Energy, Inc. and Owners of Colstrip 1 and 2, and 3 and 4 (incorporated herein by reference to Exhibit (10)-59 to Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

*** 10.18 Amendment dated as of June 1, 1968, to Power Sales Contract between Public Utility District No. 1 of Chelan County, Washington and Puget Sound Energy, Inc. (Rocky Reach Project) (incorporated herein by reference to Exhibit (10)-66 to Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

*** 10.19 Transmission Agreement dated as of December 30, 1987 between the Bonneville Power Administration and Puget Sound Energy, Inc. (Rock Island Project) (incorporated herein by reference to Exhibit (10)-74 to Report on Form 10-K for the fiscal year ended December 31, 1988, Commission File No. 1-4393).

*** 10.20 Amendment No. 1 to the Colstrip Project Transmission Agreement dated as of February 14, 1990 among The Montana Power Company, The Washington Water Power Company (Avista), Portland General Electric Company, PacifiCorp and Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit (10)-91 to Report on Form 10-K for the fiscal year ended December 31, 1990, Commission File No. 1-4393).

*** 10.21 Amendment of Seasonal Exchange Agreement, dated December 4, 1991 between Pacific Gas and Electric Company and Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit (10)-107 to Report on Form 10-K for the fiscal year ended December 31, 1991, Commission File No. 1-4393).

*** 10.22 Capacity and Energy Exchange Agreement, dated as of October 4, 1991 between Pacific Gas and Electric Company and Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit (10)-108 to Report on Form 10-K for the fiscal year ended December 31, 1991, Commission File No. 1-

4393).

***	10.23	General Transmission Agreement dated as of December 1, 1994 between the Bonneville Power Administration and Puget Sound Energy, Inc. (BPA Contract No. DE-MS79-94BP93947) (incorporated herein by reference to Exhibit 10.115 to Report on Form 10-K for the fiscal year ended December 31, 1994, Commission File No. 1-4393).
***	10.24	PNW AC Intertie Capacity Ownership Agreement dated as of October 11, 1994 between the Bonneville Power Administration and Puget Sound Energy, Inc. (BPA Contract No. DE-MS79-94BP94521) (incorporated herein by reference to Exhibit 10.116 to Report on Form 10-K for the fiscal year ended December 31, 1994, Commission File No. 1-4393).
	10.25	Amendment to Gas Transportation Service Contract dated July 31, 1991 between Washington Natural Gas Company and Northwest Pipeline Corporation (incorporated herein by reference to Exhibit 10-E.2 to Washington Natural Gas Company's Form 10-K for the fiscal year ended September 30, 1995, Commission File No. 1-11271).

	10.26	Firm Transportation Service Agreement dated January 12, 1994 between Northwest Pipeline Corporation and Washington Natural Gas Company for firm transportation service from Jackson Prairie (incorporated herein by reference to Exhibit 10-P to Washington Natural Gas Company's Form 10-K for the fiscal year ended September 30, 1994, Commission File No. 1-11271).
	10.27	Product Sales Contract dated December 13, 2001 and Amendment No. 1 thereto, between Public Utility District No. 2 of Grant County, Washington, and Puget Sound Energy, Inc., relating to the Priest Rapids Project (incorporated herein by reference to Exhibit 10-1 to Puget Sound Energy's Report on Form 10-Q for the quarter ended June 30, 2002, File No. 1-4393).
	10.28	Reasonable Portion Power Sales Contract dated December 13, 2001 and Amendment No. 1 thereto, between Public Utility District No. 2 of Grant County, Washington, and Puget Sound Energy, Inc., relating to the Priest Rapids Project (incorporated herein by reference to Exhibit 10-2 to Puget Sound Energy's Report on Form 10-Q for the quarter ended June 30, 2002, Commission File No. 1-4393).
	10.29	Additional Products Sales Agreement dated December 13, 2001, and Amendment No. 1 thereto, between Public Utility District No. 2 of Grant County, Washington, and Puget Sound Energy, Inc., relating to the Priest Rapids Project (incorporated herein by reference to Exhibit 10.3 to Puget Sound Energy's Report on Form 10-Q for the quarter ended June 30, 2002, Commission File No. 1-4393).
**	10.30	Form of Executive Employment Agreement with Executive Officers (incorporated herein by reference to Exhibit 10.1 to Puget Energy's and Puget Sound Energy's Current Report on Form 8-K, dated April 3, 2009, Commission file Nos. 1-16305 and 1-4393).
**	10.31	Puget Sound Energy Inc. Amended and Restated Supplemental Executive Retirement Plan effective January 1, 2009 (incorporated herein by reference to Exhibit 10.39 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).
**	10.32	Puget Sound Energy, Inc. Amended and Restated Supplemental Executive Retirement Plan effective January 1, 2013. (incorporated herein by reference 10.35 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2012, Commission File Nos. 1-16305 and 1-4393).
**	10.33	Puget Sound Energy, Inc. Amended and Restated Deferred Compensation Plan for Key Employees effective January 1, 2009. (incorporated herein by reference to Exhibit 10.40 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 20018, Commission File No. 1-6305).
**	10.34	Puget Sound Energy, Inc. Amended and Restated Deferred Compensation Plan for Nonemployee Directors effective January 1, 2009 (incorporated herein by reference to Exhibit 10.41 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393)
**	10.35	Summary of Director Compensation (incorporated herein by reference to Exhibit 10.38 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2015, Commission File No. 1-16305 and 1-4393.)
**	10.36	Puget Sound Energy, Inc. Supplemental Death Benefit Plan for Executive Employees, effective October1, 2000, as amended (incorporated herein by reference to Exhibit 10.45 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305).
**	10.37	Amendment to Puget Sound Energy, Inc. Supplemental Death Benefit Plan for Executive Employees, effective January 1, 2002, as amended (incorporated herein by reference to Exhibit 10.46 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).
**	10.38	Puget Sound Energy, Inc. Supplemental Disability Plan for Executive Employees, effective October 1, 2000 as amended (incorporated herein by reference to Exhibit 10.47 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).
**	10.39	Amendment to Puget Sound Energy, Inc. Supplemental Death Benefit Plan for Executive Employees, effective November 1, 2007, as amended (incorporated herein by reference to Exhibit 10.48 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).
**	10.40	Puget Energy, Inc. Amended and Restated 2005 Long-Term Incentive Plan, effective January 21, 2016 (incorporated herein by reference to Exhibit 10.43 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2015, Commission File No. 1-16305 and 1-4393).

**	10.41	Second Amended and Restated Credit Agreement dated May 16, 2022 among Puget Energy Inc., as Borrower, JPMorgan Chase Bank N.A., as Administrative Agent, and the lenders party thereto. (incorporated by reference to Exhibit 10.1 to Puget Energy's Current Report on Form 8-K, filed May 23, 2022, Commission File No. 1-16305).
	10.42	Amended and Restated Credit Agreement dated May 16, 2022, among Puget Sound Energy, Inc., as Borrower, Mizuho Bank, Ltd., as Administrative Agent, and the lenders party thereto. (incorporated by reference to Exhibit 10.2 to Puget Sound Energy's Current Report on Form 8-K, filed May 23, 2022, Commission file No. 1-4393).

**	10.43	Purchase Agreement, dated June 4, 2018, between Puget Sound Energy, Inc. and J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Mizuho Securities USA LLC and each of the other underwriters named in Schedule A thereto (incorporated by reference herein to Exhibit 1.1 to Current Report on Form 8-K filed on June 5, 2018, Commission File No. 1-4393).
	10.44	Term Loan Agreement, dated October 1, 2018, among Puget Energy, Toronto Dominion (Texas) LLC, as Administrative Agent, and the lenders party thereto (incorporated by reference herein to Exhibit 10.1 to Current Report on Form 8-K filed on October 3, 2018, Commission file No. 1-16305 and 1-4393).
*	21.1	Subsidiaries of Puget Energy, Inc.
*	21.2	Subsidiaries of Puget Sound Energy, Inc.
*	22.1	Issuers of Guaranteed Securities and Affiliates Whose Securities Collateralize Securities of the Registrant
*	23.1	Consent of PricewaterhouseCoopers LLP for Puget Sound Energy, Inc.
*	23.2	Consent of PricewaterhouseCoopers LLP for Puget Energy, Inc.
*	31.1	Certification of Puget Energy, Inc. - Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Mary E. Kipp.
*	31.2	Certification of Puget Energy, Inc. - Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 –Kazi Hasan
*	31.3	Certification of Puget Sound Energy, Inc. - Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Mary E. Kipp
*	31.4	Certification of Puget Sound Energy, Inc. – Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Kazi Hasan.
*	32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 – Mary E. Kipp.
*	32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 – Kazi Hasan.
*	101	Financial statements from the Annual Report on Form 10-K of Puget Energy, Inc. and Puget Sound Energy, Inc. for the fiscal year ended December 31, 2022, filed on February 23, 2023, formatted as Inline XBRL: (i) the Consolidated Statement of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Balance Sheets, (iii) the Consolidated Statements of Cash Flows, and (iv) the Notes to Consolidated Financial Statements (submitted electronically herewith).
*	101.INS	Inline XBRL Instance
*	101.SCH	Inline XBRL Taxonomy Extension Schema
*	101.CAL	Inline XBRL Taxonomy Extension Calculation
*	101.DEF	Inline XBRL Taxonomy Extension Definition
*	101.LAB	Inline XBRL Taxonomy Extension Label
*	101.PRE	Inline XBRL Taxonomy Extension Presentation
*	104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

____

* *Filed herewith.*

** *Management contract, compensatory plan or arrangement.*

*** *Exhibit originally filed with the Securities and Exchange Commission in paper format and as such, a hyperlink is not available.*

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PUGET ENERGY, INC.	**PUGET SOUND ENERGY, INC.**
/s/ Mary E. Kipp	/s/ Mary E. Kipp
Mary E. Kipp	Mary E. Kipp
President and Chief Executive Officer	President and Chief Executive Officer
Date: February 23, 2023	Date: February 23, 2023

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of each registrant and in the capacities and on the dates indicated.

Signature	Title	Date
	(Puget Energy and PSE unless otherwise noted)	
/s/ Mary E. Kipp (Mary E. Kipp)	President and Chief Executive Officer	February 23, 2023
/s/ Kazi Hasan (Kazi Hasan)	Executive Vice President and Chief Financial Officer	
/s/ Stacy Smith (Stacy Smith)	Controller and Principal Accounting Officer	
/s/ Scott Armstrong (Scott Armstrong)	Director	
/s/ Jean-Paul Marmoreo (Jean-Paul Marmoreo)	Director	
/s/ Tom King (Tom King)	Director	
/s/ Richard Dinneny (Richard Dinneny)	Director	
/s/ Barbara Gordon	Director	

(Barbara Gordon)

/s/ Chris Parker Director
(Chris Parker)

/s/ Paul McMillan Director
(Paul McMillan)

/s/ Aaron Rubin Director
(Aaron Rubin)

/s/ Grant Hodgkins Director
(Grant Hodgkins)

/s/ Martijn Verwoest Director
(Martijn Verwoest)

/s/ Steven Zucchet Director
(Steven Zucchet)

/s/ Diana Birkett Rakow Director of PSE Only
(Diana Birkett Rakow)

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Section 2: EX-21.1 (EX-21.1)

Exhibit 21.1

Puget Energy, Inc.

SUBSIDIARIES

1. Puget Sound Energy, Inc.
   355 110th Ave NE
   Bellevue, Washington 98004
   (425) 454-6363

1. Puget LNG, LLC
   355 110th Ave NE
   Bellevue, Washington 98004
   (425) 454-6363

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Section 3: EX-21.2 (EX-21.2)

Exhibit 21.2

Puget Sound Energy, Inc.

SUBSIDIARIES

1. Puget Western, Inc.
   19515 North Creek Parkway
   Suite 310
   Bothell, Washington 98011

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Section 4: EX-22.1 (EX-22.1)

EXHIBIT 22.1

Subsidiary Guarantors and Issuers of Guaranteed Securities and Affiliates Whose Securities Collateralize Securities of the Registrant

The following securities (collectively, the "Puget Energy Senior Secured Notes") issued by Puget Energy, Inc., a Washington corporation, were outstanding as of December 31, 2022:

Name of Issuer	Description of Security
Puget Energy, Inc.	3.650% Senior Secured Notes due 2025
Puget Energy, Inc.	2.379% Senior Secured Notes due 2028
Puget Energy, Inc.	4.100% Senior Secured Notes due 2030
Puget Energy, Inc.	4.224% Senior Secured Notes due 2032

<u>Pledged Security Collateral</u>

As of December 31, 2022, the obligations under the Puget Energy Senior Secured Notes were secured by pledges of the capital stock of the following affiliates of Puget Energy, Inc.:

Name of Issuer	Issuer Jurisdiction of Organization	Number of Shares Owned	Percent of Interest Owned	Percent of Interest Pledged
Puget Sound Energy, Inc.	Washington	85,903,791	100%	100%

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Section 5: EX-23.1 (EX-23.1)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-266649) of Puget Sound Energy, Inc. of our report dated February 23, 2023 relating to the financial statements and financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/PricewaterhouseCoopers LLP
Portland, Oregon
February 23, 2023

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Section 6: EX-23.2 (EX-23.2)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3/A (No. 333-263015) of Puget Energy, Inc. of our report dated February 23, 2023 relating to the financial statements and financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/PricewaterhouseCoopers LLP
Portland, Oregon
February 23, 2023

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Section 7: EX-31.1 (EX-31.1)

Exhibit 31.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002**

I, Mary E. Kipp, certify that:

I have reviewed this report on Form 10-K of Puget Energy, Inc.;

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's Board of Directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2023

/s/ Mary E. Kipp
Mary E. Kipp
President and Chief Executive Officer

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Section 8: EX-31.2 (EX-31.2)

Exhibit 31.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Kazi Hasan, certify that:

I have reviewed this report on Form 10-K of Puget Energy, Inc.;

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's Board of Directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2023

/s/ Kazi Hasan
Kazi Hasan
Executive Vice President and
Chief Financial Officer

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Section 9: EX-31.3 (EX-31.3)

Exhibit 31.3

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Mary E. Kipp, certify that:

I have reviewed this report on Form 10-K of Puget Sound Energy, Inc.;

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's Board of Directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2023

/s/ Mary E. Kipp
Mary E. Kipp
President and Chief Executive Officer

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Section 10: EX-31.4 (EX-31.4)

Exhibit 31.4

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Kazi Hasan, certify that:

I have reviewed this report on Form 10-K of Puget Sound Energy, Inc.;

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's Board of Directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2023

/s/ Kazi Hasan
Kazi Hasan
Executive Vice President and
Chief Financial Officer

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Section 11: EX-32.1 (EX-32.1)

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Report of Puget Energy, Inc. and Puget Sound Energy, Inc. (the "Companies") on Form 10-K for the year ended December 31, 2022 as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-K"), I, Mary E. Kipp, the President and Chief Executive Officer of the Companies, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Companies.

Date: February 23, 2023

/s/ Mary E. Kipp
Mary E. Kipp
President and Chief Executive Officer

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Section 12: EX-32.2 (EX-32.2)

Exhibit 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Report of Puget Energy, Inc. and Puget Sound Energy, Inc. (the "Companies") on Form 10-K for the year ended December 31, 2022 as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-K"), I, Kazi Hasan, Executive Vice President and Chief Financial Officer of the Companies, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Companies.

Date: February 23, 2023

/s/ Kazi Hasan
Kazi Hasan
Executive Vice President and Chief Financial Officer

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Docket UE-240004 & UG-240005
Exhibit AEB- X

Completely Revised and Updated

VALUATION

MEASURING AND MANAGING THE VALUE OF COMPANIES

THIRD EDITION

UNIVERSITY EDITION

McKinsey & Company, Inc.
Tom Copeland • Tim Koller • Jack Murrin

$$k_p = \frac{\text{div}}{P}$$

where k_p = The cost of preferred stock
div = The promised dividend on the preferred stock
P = The market price of the preferred stock

If the current market price is not available, use yields on similar-quality issues as an estimate. For a fixed-life or callable preferred stock issue, estimate the opportunity cost by using the same approach as for a comparable debt instrument. In other words, estimate the yield that equates the expected stream of payments with the market value. For convertible preferred issues, option-pricing approaches are necessary.

STEP 3: ESTIMATE THE COST OF EQUITY FINANCING

The opportunity cost of equity financing is the most difficult to estimate because we can't directly observe it in the market. We recommend using the capital asset pricing model (CAPM) or the arbitrage pricing model (APM). Both approaches have problems associated with their application, including measurement difficulty. Many other approaches to estimating the cost of equity are conceptually flawed. The dividend yield model (defined as the dividend per share divided by the stock price) and the earnings-to-price ratio model substantially understate the cost of equity by ignoring expected growth.

The Capital Asset Pricing Model

The CAPM is discussed at length in all modern finance texts (for example, see Brealey and Myers, 1999, or Copeland and Weston, 1992).[6] These detailed discussions will not be reproduced here. (In this section, we assume that you are generally familiar with the principles that underlie the approach.) The CAPM postulates that the opportunity cost of equity is equal to the return on risk-free securities plus the company's systematic risk (beta) multiplied by the market price of risk (market risk premium). The equation for the cost of equity (k_s) is as follows:

[6] T. Copeland and J. Weston, *Financial Theory and Corporate Policy*, 3rd ed. (Reading, MA: Addison-Wesley, 1992); and R. Brealey and S. Myers, *Principles of Corporate Finance*, 5th ed. (New York: McGraw-Hill, 1999).

by interest payments; preferred stockholders are compensated by fixed dividend payments; and the firm's remaining income belongs to its common stockholders and serves to "pay the rent" on stockholders' capital. Management may either pay out earnings in the form of dividends or retain earnings for reinvestment in the business. If part of the earnings is retained, an *opportunity cost* is incurred: Stockholders could have received those earnings as dividends and then invested that money in stocks, bonds, real estate, and so on. *Thus, the firm should earn on its retained earnings at least as much as its stockholders themselves could earn on alternative investments of equivalent risk.*

What rate of return can stockholders expect to earn on other investments of equivalent risk? The answer is k_s, because they can earn that return simply by buying the stock of the firm in question or that of a similar firm. Therefore, if our firm cannot invest retained earnings and earn at least k_s, then it should pay those earnings to its stockholders so that they can invest the money themselves in assets that do provide a return of k_s.

Whereas debt and preferred stocks are contractual obligations which have easily determined costs, it is not at all easy to estimate k_s. However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive—no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand.

SELF-TEST QUESTIONS

What are the two types of common equity whose costs must be estimated?

Explain why there is a cost for retained earnings.

THE CAPM APPROACH

As we saw in Chapter 5, the Capital Asset Pricing Model is based on some unrealistic assumptions, and it cannot be empirically verified. Still, because of its logical appeal, the CAPM is often used in the cost of capital estimation process.

Under the CAPM we assume that the cost of equity is equal to the risk-free rate plus a risk premium that is based on the stock's beta coefficient and the market risk premium as set forth in the Security Market Line (SML) equation:

$$\begin{aligned} k_s &= \text{Risk-free rate} + \text{Risk premium} \\ &= \quad k_{RF} \quad + (k_M - k_{RF})b_i. \end{aligned}$$

Given estimates of (1) the risk-free rate, k_{RF}, (2) the firm's beta, b_i, and (3) the required rate of return on the market, k_M, we can estimate the required rate of return on the firm's stock, k_s. This required return can then be used as an estimate of the cost of retained earnings.

ESTIMATING THE RISK-FREE RATE

The starting point for the CAPM cost of equity estimate is k_{RF}, the risk-free rate. There is really no such thing as a truly riskless asset in the U.S. economy. Treasury securities are free of default risk, but long-term T-bonds will suffer capital losses if interest rates rise, and a portfolio invested in short-term T-bills will provide a volatile earnings stream because the rate paid on T-bills varies over time.

Since we cannot in practice find a truly riskless rate upon which to base the CAPM, what rate should we use? Our preference—and this preference is shared by most practitioners—is to use the rate on long-term Treasury bonds. Here are our reasons:

1. Capital market rates include a real, riskless rate (generally thought to vary from 2 to 4 percent) plus a premium for inflation which reflects the expected inflation rate over the life of the security, be it 30 days or 30 years. The expected rate of inflation is likely to be relatively high during booms and low during recessions. Therefore, during booms T-bill rates tend to be high to reflect the high current inflation rate, whereas in recessions T-bill rates are generally low. T-bond rates, on the other hand, reflect expected inflation rates over a long period, so they are far less volatile than T-bill rates.

2. Common stocks are long-term securities, and although a particular stockholder may not have a long investment horizon, most stockholders do invest on a long-term basis. Therefore, it is reasonable to think that stock returns embody long-term inflation expectations similar to those embodied in bonds rather than the short-term expectations in bills. Therefore, the cost of equity should be more highly correlated with T-bond rates than with T-bill rates.

3. Treasury bill rates are subject to more random disturbances than are Treasury bond rates. For example, bills are used by the Federal Reserve System to control the money supply, and bills are also used by foreign governments, firms, and individuals as a temporary safe haven for money. Thus, if the Fed decides to stimulate the economy, it drives down the bill rate, and the same thing happens if trouble erupts somewhere in the world and money flows into U.S. dollars seeking safety. T-bond rates are also influenced by Fed actions and by international money flows, but not to the same extent as T-bill rates. This is another reason why T-bill rates are more volatile than T-bond rates and, most experts agree, more volatile than k_s.

4. T-bills are essentially free of price risk, but they are exposed to a relatively high degree of reinvestment rate risk. Long-term investors such as pension funds and life insurance companies are as concerned about reinvestment rate risk as price risk. Therefore, most long-term investors would feel equally exposed to risk if they held bills or bonds.

5. When the CAPM is used to estimate a particular firm's cost of equity over time, bond rates produce more reasonable results. When T-bill rates were low in 1977

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The model is analogous to the standard CAPM, but with the return on a minimum risk portfolio that is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who find a flatter than predicted SML, consistent with the model and other researchers' findings. An updated version of the Black-Jensen-Scholes study is available in Brealey, Myers, and Allen (2006) and reaches similar conclusions.

The zero-beta CAPM cannot be literally employed to estimate the cost of capital, since the zero-beta portfolio is a statistical construct difficult to replicate. Attempts to estimate the model are formally equivalent to estimating the constants, a and b, in Equation 6-2. A practical alternative is to employ the Empirical CAPM, to which we now turn.

6.3 Empirical CAPM

As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \acute{\alpha} + \beta \times (MRP - \acute{\alpha}) \tag{6-5}$$

where $\acute{\alpha}$ is the "alpha" of the risk-return line, a constant, and the other symbols are defined as before. All the potential vagaries of the CAPM are telescoped into the constant $\acute{\alpha}$, which must be estimated econometrically from market data. Table 6-2 summarizes[10] the empirical evidence on the magnitude of alpha.[11]

[10] The technique is formally applied by Litzenberger, Ramaswamy, and Sosin (1980) to public utilities in order to rectify the CAPM's basic shortcomings. Not only do they summarize the criticisms of the CAPM insofar as they affect public utilities, but they also describe the econometric intricacies involved and the methods of circumventing the statistical problems. Essentially, the average monthly returns over a lengthy time period on a large cross-section of securities grouped into portfolios are related to their corresponding betas by statistical regression techniques; that is, Equation 6-5 is estimated from market data. The utility's beta value is substituted into the equation to produce the cost of equity figure. Their own results demonstrate how the standard CAPM underestimates the cost of equity capital of public utilities because of utilities' high dividend yield and return skewness.

[11] Adapted from Vilbert (2004).

TABLE 6-2
EMPIRICAL EVIDENCE ON THE ALPHA FACTOR

Author	Range of alpha
Fischer (1993)	−3.6% to 3.6%
Fischer, Jensen and Scholes (1972)	−9.61% to 12.24%
Fama and McBeth (1972)	4.08% to 9.36%
Fama and French (1992)	10.08% to 13.56%
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%
Pettengill, Sundaram and Mathur (1995)	4.6%
Morin (1989)	2.0%

For an alpha in the range of 1%–2% and for reasonable values of the market risk premium and the risk-free rate, Equation 6-5 reduces to the following more pragmatic form:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta(R_M - R_F) \qquad (6\text{-}6)$$

Over reasonable values of the risk-free rate and the market risk premium, Equation 6-6 produces results that are indistinguishable from the ECAPM of Equation 6-5.[12]

An alpha range of 1%–2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the

[12] Typical of the empirical evidence on the validity of the CAPM is a study by Morin (1989) who found that the relationship between the expected return on a security and beta over the period 1926–1984 was given by:

$$\text{Return} = 0.0829 + 0.0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6% and that the market risk premium was 8% during the period of study, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2%, or 1/4 of 8%, and that the slope of the relationship is close to 3/4 of 8%. Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x(R_M - R_F) + (1 - x)\beta(R_M - R_F)$$

where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75\beta(R_M - R_F)$$

long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. Thus, it is reasonable to apply a conservative alpha adjustment. Moreover, the lowering of the tax burden on capital gains and dividend income enacted in 2002 may have decreased the required return for taxable investors, steepening the slope of the ECAPM risk-return trade-off and bring it closer to the CAPM predicted returns.[13]

To illustrate the application of the ECAPM, assume a risk-free rate of 5%, a market risk premium of 7%, and a beta of 0.80. The Empirical CAPM equation (6-6) above yields a cost of equity estimate of 11.0% as follows:

$$\begin{aligned} K &= 5\% + 0.25\,(12\% - 5\%) + 0.75 \times 0.80\,(12\% - 5\%) \\ &= 5.0\% + 1.8\% + 4.2\% \\ &= 11.0\% \end{aligned}$$

As an alternative to specifying alpha, see Example 6-1.

Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, recall from Chapter 3 that the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

[13] The lowering of the tax burden on capital gains and dividend income has no impact as far as non-taxable institutional investors (pension funds, 401K, and mutual funds) are concerned, and such investors engage in very large amounts of trading on security markets. It is quite plausible that taxable retail investors are relatively inactive traders and that large non-taxable investors have a substantial influence on capital markets.

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Interest Rate Risk and Utility Risk Premia During 1982–93

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INTRODUCTION

The risk premium method of calculating a fair return on equity for a regulated utility is frequently used in regulatory proceedings. That method considers the relationship between a utility's bond yield and its required return on equity, and is especially useful when other methods, such as the capital asset pricing model and the discounted cash flow (DCF) model exhibit less reliability.[1] Although the discounted cash flow method is the favored method for estimating a utility's cost of equity in rate proceedings, the risk premium method provides a useful check on the DCF results. This is even more important in today's financial environment because of the difficulty of measuring investor-expected growth rates in the DCF method.

If bond yields and required returns on equity move up and down in lockstep, it is straightforward to calculate the appropriate cost of equity using the risk premium method. However, if they do not, estimation of the cost of equity is much more difficult. One explanation of this variability in risk premia is differences in 'interest rate risk'. In particular, arguments have been made in rate cases that utility bonds are riskier in the 1980s than they were earlier because of the significant increase in interest rate variability that occurred in the early 1980s (primarily caused by increased inflation rate variability).[2] In particular, when capital costs, and interest rates, increase, utility bondholders, who earlier 'locked-in' at lower interest rates, miss out on those higher interest rates. Bondholders who experience this will then prospectively require an 'interest rate risk' premium, and utility bond interest rates will be correspondingly greater. Furthermore, utility bonds of differing overall risk may exhibit differing sensitivities to that 'interest rate risk'.

In contrast, the argument goes, utility common stock returns have some protection from that risk. If capital costs increase, utilities can request a rate increase to increase the allowed return. Consequently, utility common shareholders can earn the higher capital costs, and do not necessarily require an 'interest rate risk' premium.[3] Thus, over time we would not necessarily expect to see utility bond yields and required equity returns move in one-to-one lockstep. Furthermore, to the extent that there is some substitutability between utility common stocks and utility bonds as interest rate risk associated with bonds increases, investors may increase their preferences for utility stocks. This should tend to decrease required returns on utility common stock.

Berry (1995) performed an analysis of the impact of interest rate (and capital cost) risk on interest rates and dividend yields. Those results indicate that interest rates are positively related to interest rate variability, but dividend yields are not affected by dividend yield variability. However, that study focused on *dividend yields*, which are easy to measure, and did not consider required equity returns which are much more difficult to measure. Furthermore, that study did not focus on risk premia, and the relationship between bond yields and required returns on equity, as does this paper. This paper utilizes required returns, as measured by Commission-allowed returns, in the risk premium analysis.

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Other studies have shown that there is an inverse relationship between interest rates and risk premia in recent years, but not in earlier years. Carleton *et al.* (1983) found that there was no relationship between electric utility risk premia and interest rates during the 1970s. Brigham *et al.* (1985) estimated a positive relationship between risk premia and interest rates for the 1966–79 period and a negative relationship between the variables during the 1980–84 period. They attributed this to increased inflation risk and its effect on interest rates. Similarly, Harris (1986) showed that there was a negative relationship between utility risk premia and interest rates during the 1982–84 period. Harris and Marston (1992) concluded that there was a negative relationship between the S&P 500 risk premia and interest rates for the 1982–91 period. However, none of these studies used Commission-allowed returns in the calculations of risk premia.

This paper considers two factors not previously considered in the literature. First, allowed returns are used as a proxy for required returns on equity, with appropriate consideration for partial adjustment. Second, explicit usage is made of measures of interest rate risk to gauge their impact on risk premia. Regression analyses is employed to estimate the effects of utility bond yields, interest rate variability, and time trends on required returns on equity and risk premia over the period 1982–93. In the second section, we present a simple regression model, which tests for an inverse relationship between required returns on equity and interest rates. This model, while not very sophisticated, has the inherent advantage that it can be easily used to estimate risk premia. In the third section, we consider a more complex model which explicitly considers various measures of interest rate variability, as well as interest rate levels.

REGRESSION RESULTS WITH INTEREST RATES

A common formulation of the risk premium is:

$$K = YD + RP \qquad (1)$$

where K is the required return on common equity, YD is the utility's current cost of long-term debt (yield) and RP is the risk premium. Since YD is directly measurable, and *if* RP can be properly measured, K can then be directly estimated.[4] However, there are two general problems with the implementation of a risk premium methodology:

1. The estimation of RP is often based on historical earned returns, which may or may not be indicative of *required* returns; and
2. The level of RP may not be constant through time. In particular, there may be an inverse relationship between interest rates and risk premia.[5]

To address the first problem we use Commission-allowed returns as a reasonable surrogate for required returns, with a partial adjustment feature, as will be discussed later. Commissions and their staff spend a significant amount of time in rate cases considering the determination of a utility's appropriate return on equity. As discussed earlier, the primary method employed is the DCF method, which, when performed properly, estimates the required return on equity.[6] Furthermore, Commission-allowed returns may represent better estimates of equity costs, than DCF methods using analysts' forecasts, since Commissions comprehend a wide variety of cost of capital methods.

For illustration we have arrayed risk premia by year in Table 1. For comparative purposes we also show the estimated risk premia using the long-term US Treasury bond yield. Note that there is a general upward trend in risk premia associated with Moody's utility bond yields, which occurs during a period of generally decreasing interest rates. Furthermore, the estimated risk premia are less than those reported in Harris and Marston (1992). This can be attributed to two factors. First, utilities are generally less risky than the S&P 500 which were used in the Harris and Marston study, with corresponding lower required returns. Second, Commission-allowed returns may incorporate lower DCF growth rates than the analysts' forecasts used by Harris and Marston.

Finally, risk premia for Treasury bonds, shown in Table 1, appear to be fairly stable, albeit with a slight upward drift over the 1982–93 period. Moody's yields fell by much more (777 basis points) over that period, than did Treasury yields (578 points). An explanation for this is provided in Berry (1995). As shown there, although there is a close one-to-one relationship between Moody's utility bond yields and Treasury yields, interest rate risk had a significant impact on Moody's

Table 1. Equity Risk Premia

Year (1)	US Treasury Bond Yields (2) (%)	Allowed Return on Equity (3) (%)	Equity Risk Premia on Treasury Yields [(3)-(2)] (4) (%)	Moody's Utility Bond Yields (5) (%)	Equity Risk Premia on Moody's Yields [(3)-(5)] (6) (%)
1982	12.23	15.46	3.23	15.33	0.13
1983	10.84	15.18	4.34	13.31	1.87
1984	11.99	15.25	3.26	14.03	1.22
1985	10.75	14.38	3.63	12.29	2.09
1986	8.14	13.2	5.06	9.46	3.74
1987	8.64	12.86	4.22	9.98	2.88
1988	8.98	12.82	3.84	10.45	2.37
1989	8.58	12.92	4.34	9.66	3.26
1990	8.74	12.63	3.89	9.76	2.87
1991	8.16	12.41	4.25	9.21	3.20
1992	7.52	11.84	4.32	8.57	3.27
1993	6.45	11.54	5.09	7.56	3.98
Change 1982–93	−5.78	−3.92	+1.86	−7.77	+3.85

Note: 1993 data are partial year.

yields. The decrease in interest rate risk during the 1980s, consequently, caused an incremental decrease in Moody's yields, in excess of that corresponding to the decrease in Treasury yields.[7] As will be discussed later, although the risk premia associated with Treasury bonds appear to be fairly stable during the 1982–93 period, there are specific reasons for that, which will not necessarily be repeated in the future.

In our regression analysis we use allowed returns and the corresponding bond yields for that utility's Moody's bond rating from 6 months earlier than the date of the Commission rate order.[8] This provides a better matching since the evidentiary record on the required return on equity is usually developed some months before the date of the rate order. The data on allowed returns was obtained from various editions of *Public Utilities Fortnightly* (1983–93).[9] The data on Moody's bond yields was obtained from various editions of *Moody's Public Utility Manual* (1982–93). This yielded a total of 1226 rate case observations over the period 1982–93. For each month we averaged the cross-sectional data to obtain 130 usable time series observations.[10]

Consistent with Equation (1), let K_t^* represent the required return on equity at time t such that

$$K_t^* = RP_t + YD_t \tag{2}$$

where RP_t and YD_t are the risk premium and current cost of debt at time t, respectively. To allow for a varying risk premium set

$$RP_t = \alpha + \beta YD_t. \tag{2a}$$

Postulate a regulator adjustment function of the form:

$$K_t - K_{t-1} = \gamma(K_t^* - K_{t-1}), \quad 0 < \gamma < 1 \tag{3}$$

where K_t is the allowed return at time t and γ is the adjustment factor. This equation implies an inertia on the part of regulators such that with a change in the required return on equity from the prior period's allowed return on equity, $K_t^* - K_{t-1}$, the regulator only moves part way to a new allowed return. The greater the value of γ, the greater the degree of regulator adjustment.[11]

Substitution of Equation (2) into Equation (3) yields

$$K_t = \gamma RP_t + \gamma YD_t + (1 - \gamma)K_{t-1} \tag{4}$$

or

$$K_t = \alpha\gamma + (1 + \beta)\gamma YD_t + (1 - \gamma)K_{t-1} \tag{4a}$$

For purposes here, we used the allowed return from 1 month earlier. Regulators are aware of recent allowed returns and will likely partially base their current allowed return awards on those recent historical allowed returns, consistent with Equation (3).[12] We then performed an ordinary least squares regression of the allowed returns on the corresponding bond yields and lagged allowed returns. This resulted in the following regression equation:

$$K_t = 0.03337 + \underset{(6.11)}{0.22301\,YD} + \underset{(8.58)}{0.56788 K_{t-1}},$$
$$(\text{Durbin–Watson} = 2.41,\ R^2 = 0.905). \qquad (5)$$

The t-statistics are shown in parentheses, and indicate significance for both independent variables at the 1% level. The implied value of γ, the adjustment factor, is $1 - 0.56788 = 0.43212$.

The implied risk premium equation, corresponding to Equation (2a), is

$$RP_t = 0.07722 - 0.48392\,YD_t. \qquad (6)$$

Equation (6) indicates the presence of an inverse relationship between risk premia and interest rates. For every 100 basis point drop in interest rates, the risk premium *increases* by approximately 48 basis points and the cost of equity decreases by approximately 52 basis points. Conversely, for every 100 basis point increase in interest rates, the risk premium *decreases* by approximately 48 basis points and the cost of equity increases by approximately 52 basis points.

To the extent interest rate variability is a major factor in the level of capital costs, we would expect to empirically observe this inverse relationship between risk premia and interest rates.[13] That is, as interest rate variability increases, interest rate risk increases, interest rates increase, and risk premia fall since utility equity costs change very little, or decrease, for the reasons mentioned in the introduction. The converse would be true in the case of a decrease in interest rate variability.[14]

An alternative formulation of Equation (1) is

$$K_t^* = RP_t + GOV_t, \qquad (7)$$

where GOV_t is the yield on long-term US Treasury bonds and RP_t is the corresponding risk premium. Performing a similar regression analysis with GOV instead of YD produces:

$$K_t = 0.1981 + \underset{(3.74)}{0.16016 GOV_t} + \underset{(12.09)}{0.73703 K_{t-1}},$$
$$(\text{Durbin–Watson} = 2.56,\ R^2 = 0.889). \qquad (8)$$

The R^2 is statistically significant at the 1% level with both independent variables statistically significant.

The implied risk premium equation, corresponding to Equation (2a), is

$$K_t^* = 0.07533 - 0.39096 GOV_t. \qquad (9)$$

This formulation, too, indicates an inverse relationship between risk premia, measured relative to Treasury bonds, and Treasury bond yields. In particular, note that for a given 100 basis point increase in interest rates the risk premium decreases by 39 basis points. The relative change in risk premia is not as great, which is attributable to less interest rate variability and interest rate risk associated with Treasury bonds.[15] Over the 1982–93 period, while Treasury yields fell by 578 basis points, Moody's utility bond yields fell by 777 basis points.

REGRESSION RESULTS WITH BOND YIELD VARIABILITY

A factor that could directly and significantly affect risk premia is investor-perceived variability in utility bond yields. It is likely that historical variability in those bond yields would impact investor perceptions of interest rate risk and increase utility bond yields. Furthermore, to the extent that there is some substitutability between utility common stocks and utility bonds, as interest rate risk associated with bonds increases, investors may increase their preferences for utility stocks. This should tend to decrease required returns on utility common stock.[16] Both of these effects will tend to reduce the risk premium when utility bond interest rate risk increases.

While some of that interest rate variability may be picked up in the data on interest rate levels, those interest rate levels also reflect other factors, such as general tightness (or laxity) in capital market conditions, prevalence of call provisions, and differential tax wedges.[17] Thus, we performed a regression analysis that explicitly included a measure for interest rate variability. An obvious measure is the standard deviation (S.D.) in interest rates in the immediate past. If our hypothesis is correct, an increase in the S.D. should decrease RP.

We considered two different historical timeframes for estimating the S.D.: 3 years and 5 years (*SD3* and *SD5*, respectively). For example, with the 3 year time frame, the S.D. at month n is calculated using the 36 months prior to month n. With the 5-year time frame, the prior 60 months were used. Each of these measures was calculated separately for bond yields for Moody's *Aaa*, *Aa*, *A* and *Baa* utility bonds and then averaged across bond ratings to obtain the average *SD3* and *SD5* for each month.

Table 2. Regression Results With *YD*, Dependent Variable = *K*

Variable				
Constant	0.1077	0.0981	0.0790	0.1001
t	−0.0002** (−7.25)	−0.0002** (−6.16)	−0.0001** (−4.47)	−0.0002** (−6.09)
YD	0.2584** (7.55)	0.2032** (6.12)	0.1947** (5.57)	0.1950** (5.89)
SD3	−0.5087** (−5.31)			
RMSD3		−0.1695** (−3.91)		
SD5			−0.1282 (−1.43)	
RMSD5				−0.1307** (−3.83)
K_{t-1}	0.1302 (1.59)	0.2131* (2.60)	0.3312** (4.18)	0.2099* (2.53)
R^2	0.9332**	0.9270**	0.9194**	0.9267**
Durbin-Watson	2.06	2.08	2.15	2.07
N	130	130	130	130

Note: t-statistics in parentheses. * and** indicate significance at the 5% and 1% levels, respectively.

These are reasonable historical time frames for purposes of estimating forward-looking investor expectations of interest rate risk. Of course, if there has been little change in these S.D.s during the sample period, then none of this matters. However, as discussed in Berry (1995) there has been significant volatility in bond yields. This has led to sharp increases in S.D.s in the early 1980s (almost triple the level in the 1970s), with some decrease in the latter 1980s.

Another way of gauging this variability is to consider the deviation of the immediately preceding month's yield from the relevant prior months' yields. As in the case of S.D.s, 3- and 5-year lags were considered. For example, in the case of 3 years, the formula used to calculate the root mean square deviation (*RMSD*) in month n is

$$RMSD3(n) = \left(\left[\sum_{i=n-36}^{n-1} (YD_{n-1} - YD_i)^2\right]/36\right)^{1/2} \tag{10}$$

where YD_{n-1} is the yield in the immediately preceding month and YD_i, $i = 1, \ldots, n-1$, corresponds to the yields in the prior months. An analogous formula for *RMSD* (*RMSD5*) was used for the case of 5 years. As in the cases for *SD3* and *SD5*, different data series were calculated for the four Moody's bond ratings and then averaged across bond ratings.

The *RMSD* may be an appropriate measure of the risk perceived by an investor since it measures the potential interest rate swings (based on prior months' interest rates) relative to the immediately preceding month's yield. In contrast, the variable S.D. measures interest variability over a prior time frame relative to the mean over that same time frame. That mean does not necessarily equal a current yield, and hence may underestimate investor perceptions with regard to potential interest rate variability. Thus, usage of the *RMSD* assumes that, in month n, investors may look at month $n-1$'s yield relative to prior months' interest rates to gauge the full impact of any potential interest rate swing. Note that, as discussed in Berry (1995) the trends in *RMSD* are similar to those of S.D.To comprehend for the possibility of a time trend in risk premia we included a monthly trend variable, t. This type of variable was discussed in Morin (1994), pp. 291–292) and was statistically significant there.

Our more complete formulation using *SD3* is then:

$$K_t^* = RP_t + YD_t \tag{11}$$

where

$$RP_t = \alpha + \beta t + \delta YD_t + \theta SD3_t. \tag{11a}$$

Assuming a regulator adjustment function as shown in Equation (3) and substituting Equations (11) and (11a) into Equation (3) produces our regression equation:

$$K_t = \alpha\gamma + \beta\gamma t + (\delta + 1)\gamma YD_t + \theta\gamma SD3_t + (1-\gamma)K_{t-1}. \tag{12}$$

Similar regression equations were used for *SD5*, *RMSD3* and *RMSD5*, where each of those variables were used in place of *SD3*. Our hypotheses are that the coefficient associated with t will be negative (consistent with Morin), the coefficient associated with *YD* will be positive, and that the coefficient associated with *SD3* (*SD5*, *RMSD3*, *RMSD5*) will be negative, as investors shift their relative preference to utility stock as interest rate risk on utility bonds increase.

Table 3. Implied Risk Premium Results, Dependent Variable = *RP*

Variable				
Constant	0.1238	0.1247	0.1181	0.1267
t	−0.0002	−0.0003	−0.0002	−0.0003
YD	−0.7029	−0.7418	−0.7089	−0.7532
SD3	−0.5849			
RMSD3		−0.2154		
SD5			−0.1917	
RMSD5				−0.1654

Table 5. Implied Risk Premium Results, Dependent Variable = *RP*

Variable				
Constant	0.1366	0.1390	0.1208	0.1408
t	−0.0004	−0.0003	−0.0002	−0.0003
GOV	−0.7906	−0.8169	−0.7399	−0.8215
SD3	−0.3357			
RMSD3		−0.1848		
SD5			0.1045	
RMSD5				−0.1655

The dependent variable, *K*, was then regressed on the three independent variables: time, yield and measures of variability in yields. Those four regression results are shown in Table 2.

Note that the regression slope coefficients are generally significant, although the coefficient for *SD5* was not. There is a statistically significant downward time trend, which is consistent with the result in Morin. The effects of *YD* on *K* are positive and significant. Three of the four coefficients associated with interest rate risk, *SD3*, *RMSD3* and *RMSD5* are significant and negative as was hypothesized. Finally, note that all of the slope coefficients associated with *YD* are significantly less than one, which supports the hypothesis that as interest rates decrease risk premia increase.

As can be seen in Table 2, the adjustment coefficients are in the range 67–87%, which are higher than the adjustment coefficient of 43% from Equation (5). This can be explained by noting that Equation (5) does not include the other factors shown in Table 2 (in particular, interest rate variability). Consequently, the adjustment coefficient measurement in Equation (5) is clouded by the effects of the other factors. It appears that regulators are not adjusting *K* to *K** very much (only 43%), simply because *K* is also reacting to other factors not captured in Equation (5). Table 2 properly captures those additional effects and isolates the larger adjustment coefficient effect.

The implied risk premium results, corresponding to Equation (11a), are shown in Table 3. As can be seen there, the coefficient associated with *YD* is between approximately −0.70 and −0.75. This indicates that each increase in utility bond yields of 100 basis points produces a decrease in the risk premium of 70 to 75 basis points. Increases in interest rates result in decreases in risk premia. Furthermore, the negative slope coefficients associated with interest rate risk, imply smaller risk premia as hypothesized. The trend variable in Table 3 has a negative slope, which is consistent with results reported in Morin (1994).[18]

To some extent the variable *YD* may include both the effects of general tightness or laxity in financial markets and interest rate risk. In order to better focus on the two separate factors, it would be appropriate to replace *YD* with *GOV* in

Table 4. Regression Results With *GOV*, Dependent Variable = *K*

Variable				
Constant	0.0781	0.0818	0.0639	0.0874
t	−0.0002** (−4.85)	−0.0002** (−5.10)	−0.0001** (−3.21)	−0.0002** (−5.44)
GOV	0.1197** (2.99)	0.1078** (2.66)	0.1376** (3.18)	0.1108** (2.80)
SD3	−0.1919 (−1.85)			
RMSD3		−0.1088* (−2.21)		
SD5			0.0553 (0.54)	
RMSD5				−0.1027** (−2.71)
K_{t-1}	0.4283** (5.30)	0.4113** (5.04)	0.4709** (6.01)	0.3794** (4.55)
R^2	0.9092**	0.9102**	0.9069**	0.9119**
Durbin-Watson	2.18	2.17	2.24	2.13
N	130	130	130	130

Note: *t*-statistics are in parentheses. * and ** indicate significance at the 5% and 1% levels, respectively.

Equations (11) and (11a), since *GOV* will more directly reflect changes in the supply and demand for loan funds, without the effect of utility bonds' interest rate risk. The corresponding equations with *SD3* are:

$$K_t^* = RP_t + GOV_t \qquad (13)$$

$$RP_t = \alpha + \beta t + \delta GOV_t + \theta SD3_t \qquad (13a)$$

These Equations focus on the relationship between utility stocks and government bonds. Assuming an adjustment mechanism as shown in Equation (3) a regression equation analogous to Equation (12) can be developed. Those regression results are shown in Table 4 and are similar to those from Table 2. However, note that the slope coefficients associated with *GOV* are smaller than those associated with *YD* in Table 2. This is consistent with the results in Berry (1995) wherein it was shown that *GOV* had a larger effect on utility bond yields than on utility common stock dividend yields. Given an imperfect, although positive, relationship between Treasury bonds and utility bonds, and an imperfect relationship between utility bonds and utility stocks, it naturally follows that there would be an even more imperfect relationship between Treasury bonds and utility stocks. This means that there is more substitutability between utility common stocks and utility bonds than between utility stocks and US Treasury bonds. A further point to note from Table 4 is that the slope coefficients associated with S.D. are statistically insignificant, while those associated with *RMSD* are significant.

The implied risk premium results, corresponding to Equation (13a) are shown in Table 5. As can be seen there, the coefficient associated with *GOV* is between approximately -0.74 and -0.82 less than those associated with *YD* in Table 3. This is consistent with the point raised above concerning relative substitutability between stocks and bonds. An increase in Treasury yields of 100 basis points produces an increase of 18–26 basis points in the cost of equity, and a corresponding decrease in the risk premium of 74–82 basis points. In sharp contrast to the reported results in Table 1, controlling for other factors, risk premia relative to Treasury yields are not necessarily stable, but change as Treasury yields change. Increases in Treasury yields result in decreases in risk premia, and those decreases are greater than those associated with similar increases in utility bond yields. Furthermore, the negative slope coefficients associated with utility bond interest rate risk, imply smaller risk premia as hypothesized. The trend variable in Table 5 has a negative slope, which is consistent with results reported in Morin (1994), as well as in Table 3.

CONCLUSIONS

This paper examined, through regression analysis, the possibility that there is an inverse relationship between risk premia and both interest rates and interest rate risk in the utility industry. We demonstrated that that is the case over the 1982–93 time period. Furthermore, it was shown that there is a statistically significant basis for asserting that risk premia increase as interest rates decrease. Our analysis also indicated that there was a downward time trend in risk premia in that period. All of these phenomena occurred with either utility bond yields or long-term US Treasury bond yields. However, for an equivalent increase in either utility bond yields or Treasury yields, required equity returns increase by a slightly greater amount with regard to utility bond yields.

It was also shown that regulators may exhibit an inertia in their setting of allowed returns, such that they move partially to the new required return, in the event capital conditions warrant a change. The degree of movement is in the range of 50–80% relative to the prior month's allowed return.

There are several policy implications from the above analysis. First, when regulators use the risk premium method for setting the allowed return on equity, they should consider the degree of recent interest rate variability and consequent interest rate risk, in comparing utility common stocks and utility bonds. The appropriate risk premium will be narrower the greater the interest rate risk. As demonstrated here, the better measure of interest rate risk is *RMSD*, not S.D. Second, objective regulators who attempt to utilize the risk premium method should implicitly compensate for the indicated regulator inertia. For example, calculate the risk premium using K^*, rather than K. Third, while Table 1 implies that risk premia relative to Treasury bonds are more stable, that is not the case when consideration is made for other factors, as shown in Tables 4 and 5. There is not necessarily any gain in precision in using a risk premium method based on Treasury bonds.

Fourth, if the US enters a period of relative stability in interest rates, we are likely to see utility risk premia increase, a phenomenon utility executives nor regulators have any degree of control over. This widening will not occur because of increases in required equity returns, but because of relatively lower interest rates and less interest rate risk.

NOTES

1. See Bonbright *et al.*, 1988 (pp. 317–28) for a discussion of these methods.
2. Gordon and Halpern (1976) show that an increase in variable and uncertain inflation will theoretically decrease the spread between bond and share yields. This acts through the Fisher effect and the resultant increase in interest rate uncertainty. Examples of rate cases where this argument has been made are Arkansas Public Service Commission (1987), Docket No. 87-070-U, Federal Energy Regulatory Commission (1986), Docket Nos. EL86-58-000 and EL86-59-000, Hawaii Public Utility Commission, Docket No. 4156, Kentucky Public Service Commission, Case No. 8045, and Pennsylvania Public Utility Commission, Docket R-811510.
3. These points are noted in Brigham *et al.* (1985) and Taylor and Peake (1982).
4. See Ibbotson Associates (1993), Carleton *et al.* (1983), Brigham *et al.* (1985) and Harris (1986) for a discussion of risk premia.
5. See Brennan (1982), Brigham *et al.* (1985) and Harris (1986). Other sources are Harris and Marston (1992), Gordon and Halpern (1976) and Federal Energy Regulatory Commission Staff (1992).
6. This approach was also taken in the Federal Energy Regulatory Commission (1992) Staff study.
7. During the same period, any interest rate risk associated with Treasury bonds was not as large, nor did it exhibit as large a decrease.
8. Given the rate case process (testimony, hearing, order writing) a 6 month lag is reasonable. However, if the 6 month period is either too long or short, the analysis here would only result in a mis-estimate of the intercept term, not the slope coefficients. For example, in a period of increasing interest rates(non-accelerating), if the appropriate lag should have been only 3 months, the 6 month lag will result in an over-estimate of the intercept term, but no mis-estimate of the slope terms. With a non-decelerating decrease in interest rates, the intercept term will be under-estimated, with no mis-estimated slope terms. The focus of this paper is on the slope terms. Furthermore, regression analyses was also performed using (a) bond yields contemporaneous with the date of the allowed return and (b) bond yields from 12 months earlier. In both those cases, the Durbin–Watson statistics were worse and the corresponding R^2 were less than with the 6 month lag. Additionally, the slope coefficients for the *YD* and *GOV* variables were not as large, nor as significant as in the 6 month lag case. Consequently, the 6 month lag scenario was utilized here.
9. For the electric and gas rate cases the data was from *Public Utilities Fortnightly's* 'Annual Surveys', while the telecommunications data was from *Public Utilities Fortnightly's* 'Selected Utility Rate Filings'.
10. The data was aggregated into monthly data for three reasons. First, Durbin–Watson statistics can then be sensibly calculated. Second, this approach is consistent with prior studies. Third, this aggregation facilitates the partial adjustment feature. There were months when there were no reported allowed returns, which decreased our total sample size.
11. See Johnston, 1972 (pp. 300–301), for discussion of this technique.
12. This approach implicitly assumes that regulators focus on allowed returns in other jurisdictions in the prior month. This is reasonable for two reasons. First, there is a certain amount of 'peer pressure' amongst regulators wherein they generally do not want their own jurisdiction's allowed returns to be out of line with other jurisdictions, unless justified by general financial and economic circumstances (such as changes in interest rates). Second, the last allowed rate of return for a particular utility may be anywhere from 6 months to 3 years earlier. Modelling those differing periods adds unnecessary complexity to the analysis, in light of the first point raised.
13. See Berry (1995) for an empirical investigation of the impact of interest rate variability on the level of interest rates.
14. Other explanations for an inverse relationship between interest rates and risk premia have to do with call provisions and tax rates. In a high interest rate environment firms will include more call provisions in new bond issues, for which bond investors require even higher interest rate compensation. Additionally, with increasing interest rates, the tax wedge applied to interest on bonds grows relative to that on common stock due to the favorable tax treatment on the capital gains component of stock returns.
15. It could also be attributable to increased utility credit risk during that period.
16. This effect can be readily observed in the DCF method where K is calculated as $D/P+g$. D is the expected dividend, P is the stock's market price, and g is the investor-expected long-term growth rate in dividends. As P increases because of investors' relative preference for utility stocks, K will decrease.
17. As shown in Berry (1995), the impact of the tightness of capital markets has differential effects on interest rates and common stock dividend yields.
18. This negative slope coefficient associated with the time variable also provides an explanation as to why the positive interest rate slope coefficients are

smaller in Table 3 than that reflected in Equation (2). Throughout the 1982–93 period, interest rates were generally decreasing, which according to the results in Table 3, will lead to decreases in required equity returns. However, during that same period the trend variable t was increasing. This increasing trend variable implies an additional source for decreases in required equity returns over that time period. Since Equation (2) does not explicitly separate out the trend variable, the overall effect in Equation (2) includes both of these effects, which will make the Equation (2) slope coefficient larger.

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Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return

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I. Introduction

Shareholder required rates of return play key roles in establishing economic criteria for resource allocation in many corporate and regulatory decisions. Theory dictates that such returns should be forward-looking return requirements that take into account the risk of the specific equity investment.

Estimation of such returns, however, presents numerous and difficult problems. Although theory clearly calls for a forward-looking required return, investigators, lacking a superior alternative, often resort to averages of historical realizations. One primary example is the determination of equity required return as a "least risk" rate plus a risk premium where an equity risk premium is calculated as an average of past differences between equity returns and returns on debt instruments. The historical studies of Ibbotson *et al.* [9] have been used frequently to implement this approach.[1] Use of such historical risk premia assumes that past realizations are a good surrogate for future expectations and that risk premia are roughly constant over time. Additionally, the choice of a time period over which to average data under such a procedure is essentially arbitrary. Carleton and Lakonishok [3] demonstrate empirically some of the problems with such historical premia when they are disaggregated for different time periods or groups of firms.

Recently Brigham, Shome, and Vinson [2] surveyed work on developing *ex ante* equity risk premia with particular emphasis on regulated utilities. They presented their own risk premia estimates, which make use of financial analysts' forecasts as surrogates for investor expectations.

The current paper follows an approach similar to Brigham *et al.* and derives equity required returns and risk premia using publicly available expectational

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[1]Many leading texts in financial management use such historical risk premia to estimate a market return. See for example, Brealey and Myers [1]. Often a market risk premium is adjusted for the observed relative risk of a stock.

Exhibit 7. Changes in Equity Risk Premia Over Time — Entries are Coefficient (t-value)

Regression	Intercept	i_{20}	σ_g	$i_c - i_{20}$	R^2
A. SP500: Dependent Variable is Equity Risk Premium*					
1.	0.140	−0.632			0.43
	(8.15)†	(−4.95)†			
2.	0.118	−0.660	0.754		0.58
	(7.10)†	(−5.93)†	(3.32)†		
3.	0.069	−0.235		1.448	0.57
	(3.44)†	(−1.76)		(4.18)†	
4.	0.030	−0.177	0.855	1.645	0.79
	(2.17)†	(−2.07)†	(4.68)†	(7.63)†	

Regression	Intercept	i_{20}	σ_g	$i_u - i_{20}$	R^2
B. SPUT: Dependent Variable is Equity Risk Premium*					
1.	0.110	−0.510			0.37
	(7.35)†	(−4.41)†			
2.	0.101	−0.543	0.805		0.41
	(6.28)†	(−4.68)†	(1.42)		
3.	0.051	−0.259		1.432	0.80
	(5.54)†	(−4.05)†		(8.87)†	
4.	0.049	−0.287	0.387	1.391	0.80
	(5.15)†	(−3.87)†	(0.75)	(8.14)†	

*All variables are defined in Exhibit 1 and graphed in Exhibit 6. Regressions were estimated for the 36 month period January 1982–December 1984 and were corrected for serial correlation using the Prais-Winsten method. For purposes of this regression variables are expressed in decimal form, e.g., 14% = 0.14.

†Significantly different from zero at 0.05 level using two-tailed test

cause of lower variability over time in the dispersion of FAF for utility stocks as compared to equities in general. The yield spread between utility and government bonds is significantly positively related to utility equity risk premia. And, as in the case of stocks in general, introduction of this spread substantially reduces the independent effect of interest rate levels on equity risk premia.

Given the short time series (36 months), tests for the stability of the relationships found in Exhibit 7 present difficulties. As a check, the relationships were reestimated dividing the data into two 18-month periods. For stocks in general (SP500), coefficients on σ_g and ($i_c - i_{20}$) were positive in all regressions and significantly so, except in the case of ($i_c - i_{20}$) for the second 18-month period. The coefficient of i_{20} was significantly negative in both periods. This confirms the general findings for the SP500 in Panel A of Exhibit 7. For utility stocks, results for the subperiods also matched the entire period results. The coefficients of ($i_u - i_{20}$) were significantly positive in both subperiods while those of σ_g were insignificantly different from zero. The level of interest rates (i_{20}) had a significant negative effect in both subperiods.

In summary, the estimated risk premia change over time and the patterns of such change are directly related to changes in proxies for the risks of equity investments. Risk premia for both stocks in general and utilities are inversely related to the level of government interest rates but positively related to the bond yield spreads which proxy for the incremental risk of investing in equities rather than government bonds. For stocks in general, risk premia also increase over time with increases in the general level of disagreement about future corporate performance.

VI. Conclusions

Notions of shareholder required rates of return and risk premia are based in theory on investors' expectations about the future. Research has demonstrated the usefulness of financial analysts' forecasts for such expectations. When such forecasts are used to derive equity risk premia, the results are quite encouraging. In addition to meeting the theoretical requirement of using expectational data, the procedure produces estimates of reasonable magnitude that behave as economic theory would predict. Both over time and across stocks, the risk premia vary directly with the perceived riskiness of equity investment.

The approach offers a straightforward and powerful aid in establishing required rates of return either for corporate investment decisions or in the regulatory arena. Since data are readily available on a wide range of equities, an investigator can analyze various proxy groups (*e.g.*, portfolios of utility stocks) appropriate for a particular decision. An additional advantage of the estimated risk premia is that they allow analysis of changes in equity return requirements over time. Tracking such changes is important for managers facing changing economic climates.

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Breakfast with the Analysts
58th Annual EEI Financial Conference

November 13, 2023

Agenda

1. **Opening Remarks and Credit Developments** - *Michael Haggarty, Associate Managing Director*

2. **Regulated Utility Sector Outlook Returns to Stable** – *Jillian Cardona, Analyst*

3. **Financial Metrics Remain Weak, But Strategic Initiatives Look to Support Credit Quality** – *Ryan Wobbrock, VP/Senior Credit Officer*

4. **Rising Capital Expenditures Will Require Equity Financing** – *Jairo Chung, VP/Senior Credit Officer*

5. **Assessing Western IOU Wildfire Credit Risk** – *Toby Shea, VP/Senior Credit Officer and Nati Martel, VP/Senior Analyst*

6. **Q&A**

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Opening Remarks and Credit Developments

Michael Haggarty, Associate Managing Director

2023 rating actions more negative, but offset by supportive regulation and California utility improvement

Positive actions have reflected improved regulation, metrics or California specific developments

- **Con Ed/CECONY** – outlook changed to positive from stable – credit supportive regulation, improved financial metrics
- **Edison/Southern California Edison** – upgraded to Baa2/Baa1 – decline in wildfire risk, utility mitigation efforts, legislative support
- **Constellation** – outlook changed to positive from stable – improving metrics, manageable debt levels, nuclear PTCs from IRA
- **Entergy Louisiana/Entergy New Orleans** – outlooks changed to stable from negative – storm cost recovery/improved regulation
- **PG&E/Pacific Gas & Electric** – outlook changed to positive – wildfire mitigation, track record, improved stakeholder relationships
- **Spire Missouri** – outlook changed to stable from negative – credit supportive rate case outcome

Negative actions have reflected weaker metrics, regulatory challenges or wildfire risks

- **DPL/DP&L** – downgraded to Ba2/Baa3 – weak financial metrics, rapidly increasing debt at utility, high debt at parent company
- **Enbridge** – outlook changed to negative from stable – US LDC acquisition adding pressure to already weak financial metrics
- **Entergy Arkansas/Entergy Mississippi** – outlooks changed to stable from positive – credit metrics to be lower than expected
- **Hawaiian Electric/HEI** – downgraded to Ba3/B1 – wildfires, potential financial liabilities, heightened uncertainty
- **PacifiCorp** – outlook changed to negative – jury finding in wildfire litigation, weakly positioned financial metrics
- **PECO Energy** – outlook changed to negative from stable – declining metrics, impact of AMT on Exelon and consolidated organization
- **Questar Gas** – outlook changed to negative from stable – reduction in authorized equity capitalization
- **Spire Alabama** – outlook changed to negative from stable – lower credit metrics, higher debt, reduction in authorized ROE
- **System Energy** – downgraded to Baa2/Ba1 – declining cash flow, regulatory challenges, sizable financial claims
- **TC Energy/TransCanada** – downgraded to Baa3/Baa2 – weak metrics, higher Coastal Gaslink costs, capital expenditure pressures

US holding company ratings remain concentrated at Baa2

Despite sector financial pressures, 90% of Baa rated holding companies have stable or positive outlooks, similar for utility subsidiaries

- **A3:** Berkshire Hathaway Energy
- **Baa1:** ALLETE, Ameren, NextEra, OGE, Pinnacle West (negative), PPL, UNS, WEC, Xcel
- **Baa2:** Alliant, AEP, Avangrid, Black Hills, CenterPoint, CMS, ConEd (positive) , Dominion, DTE, Duke, Edison, Entergy (negative), Evergy, Eversource, Exelon, IDACORP, NiSource, Otter Tail, PSEG, Sempra, Southern (positive), SW Gas, Spire
- **Baa3:** AES, Cleco, Duquesne, Emera (negative), Fortis, PNMR, Puget
- **Ba1:** FirstEnergy (on review for upgrade)
- **Ba2:** PG&E (positive), DPL

Key question going into 2024

How can the sector finance increasing capital expenditures and maintain credit ratings in this rate environment without issuing equity? Utilities have relied on:

- » Regulatory support
- » Asset sales
- » Inflation Reduction Act and other tax benefits
- » Securitization bonds
- » Hybrid securities
- » Cost control, O&M reductions and efficiencies
- » Technology advances
- » Timing of capital expenditures
- » Consolidation
- » Advance communication and transparency with Moody's

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INVESTORS SERVICE

REQUEST
FOR COMMENT

Hybrid Equity Credit, Financial Statement Adjustments and REITs: Proposed Methodology Updates

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Summary

In this Request for Comment, we propose a number of changes to the *Hybrid Equity Credit* rating methodology, published in September 2018. Based on this proposal, we also propose to make conforming changes to our *Financial Statement Adjustments in the Analysis of Non-Financial Corporations* rating methodology, published in March 2023, our *Financial Statement Adjustments in the Analysis of Financial Institutions* rating methodology, published in August 2018, and our *REITs and Other Commercial Real Estate Firms rating methodology*, published in September 2022. For purposes of the hybrid equity credit methodology, a hybrid instrument is a subordinated security (e.g., subordinate debt, preferred stock) that is not common equity and for which the omission of scheduled dividend, interest or principal payments is contractually allowable.

Our proposed approach for ascribing equity credit to hybrid securities of investment-grade issuers would provide simplified criteria based on the broad features of a hybrid instrument while retaining the key principles of our existing approach. Under our proposal, we would apply these criteria using a sequence of questions about certain key characteristics of a security, namely, about mandatory conversion features, coupon skip or deferral provisions, and maturity. Under our proposal, we would no longer consider some of the narrower technical features of hybrid instruments that we review in our existing approach. Where a security includes other features or terms that are relevant to an issuer's credit profile, but do not affect the quantitative equity credit we ascribe, we continue to consider these features in our overall credit analysis of the issuer.

The key proposed revisions to the current *Hybrid Equity Credit* methodology are as follows:

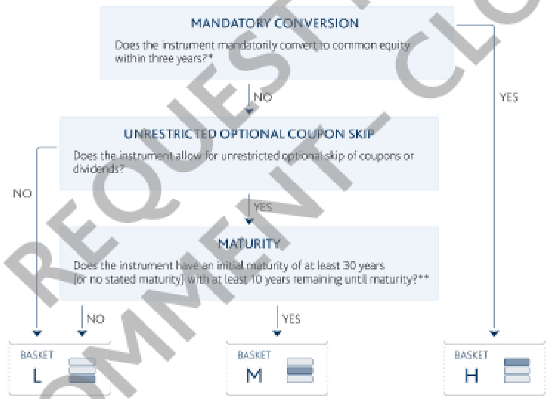
- **Simplify our framework for ascribing equity credit to hybrid instruments of investment-grade issuers.** Our proposed changes reduce the complexity of our existing framework for ascribing equity credit. We would no longer include many of the criteria of our existing approach. Instead, we would focus on a few important characteristics of hybrid instruments, including mandatory conversion features, coupon skip features, and maturity. Our proposals reflect a reconsidered approach for ascribing equity credit, one that is better aligned to how we assess hybrid instruments in the broader context of issuer credit analysis. Our proposed approach also takes into account more recent structural features of instruments and issuer behavior.

- **Modify our equity-credit classification scale.** We propose to reduce the number of baskets in our scale for equity credit to three baskets, corresponding to 0%, 50%, and 100% equity credit, from five baskets. The gradations of our proposed scale better reflect the extent to which the equity content of hybrid instruments can be distinguished.
- **Clarify how we assess shareholder loans.** We plan to update our analytical guidance to highlight that our principles for assessing the equity content of a shareholder loan, though largely unchanged, are anchored to our assessment of the financial policy and broader credit profile of the speculative grade issuer that issues the shareholder loan.

For purposes of displaying metrics (whether in credit opinions and other research and for scorecard output), we propose to implement the proposed updates described above to an issuer's most recent historical fiscal period and any subsequent financial statement periods. As a result, upon adoption of the proposed approach, an issuer's single-year metrics displayed in our published research would fully reflect the proposed updates, while the display of multi-year metrics (e.g., three-year averages) would be based on a combination of the proposed updates for the most recent period and historical hybrid basketing for prior periods.

The exhibit below illustrates how we propose to ascribe equity credit to hybrid securities of investment-grade issuers.

Exhibit 1
Ascribing equity credit to hybrid instruments[1] – Investment-grade entities



[1] The flowchart applies only to hybrid instruments, which are subordinated securities (e.g., subordinate debt, preferred stock) that are not common equity and for which the omission of scheduled dividend, interest or principal payments is contractually allowable.
* For a Yes response above, the instrument must also convert to a fixed number of common equity shares.
** Where an instrument has a meaningful coupon step-up, a Yes response to the Maturity question is replaced with a No response.
Source: Moody's Investors Service

To assist readers in understanding the proposed revisions, this RFC includes an annex with comparative examples: In the annex we illustrate how equity credit would be ascribed under our proposals to a sample of common types of hybrid instruments issued by investment-grade issuers and how that would compare to how such instruments are treated under our current approach.

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CROSS-SECTOR
RATING METHODOLOGY

Hybrid Equity Credit

This cross-sector rating methodology replaces the *Hybrid Equity Credit* methodology published in January 2017. We have removed language on notching considerations for hybrid securities, which can be found in the relevant sector methodology or in our cross-sector methodology that discusses the notching of corporate instrument ratings. We have added a new section, "Scope of This Methodology", that clarifies the sectors to which this methodology applies and replaces descriptions of the covered universe (and excluded entities) that were in other sections of the document. We have also made some purely presentational changes.

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Introduction

This methodology explains our general approach to assigning equity credit for hybrid instruments (including shareholder loans) issued by non-banks. Where hybrid instruments are material and we consider them to be relevant to our analysis of an issuer, we assign equity credit and make related financial statement adjustments.[1]

We assign equity credit to hybrid securities of investment-grade and speculative-grade issuers covered under this methodology, although our approaches to assigning equity credit for these two categories differ. For investment-grade issuers, we use an equity credit classification system that considers the benefits a hybrid instrument offers going concerns, where losses are absorbed well in advance of a broad, company-wide default and gone concerns, where losses tend not to be absorbed unless a broad, company-wide default has occurred or is imminent. For speculative-grade issuers, hybrid instruments receive either full equity credit or none, based on the characteristics of the instrument. This treatment reflects the lower certainty (relative to investment-grade issuers) that hybrid coupons will be paid, particularly if debt default can be avoided.

1 See the methodologies that describe our financial statement adjustments for financial institutions and for non-financial corporations. A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section of this report.

Exhibit 2

Illustrative Examples[†] - Assigning Equity Credit to Non-Convertible Hybrids Issued by Investment-Grade Entities

		#1	#2	#3	#4	#5	#6	#7	#8	#9	#10	#11	#12
Coupon skip	Mandatory Weak[1]		X										
	Restricted Optional[2]			X							X		
	Optional	X			X	X		X	X			X	
	Optional and Mandatory Strong[3]						X			X			X[4]
Settle-ment	Cumulative	X	X	X	X	X	X	X		X			
	Non-cumulative								X		X	X	X
Ranking*	Subordinated	X	X	X	X	X	X						
	Preferred							X	X	X	X	X	X
	Equity												
Maturity	< 30 years	X											
	30 – 59 years				X				X				
	>= 60 years		X	X		X	X	X		X	X	X	X
	Irredeemable												
Baskets		A	B	B	B	B	B	C	C	C	C	C	D

† This table is illustrative of common types of non-convertible hybrids but is not an exhaustive compendium.

* Ranking refers to Moody's classification of the security for purposes of assessing equity credit. Please see the discussion below, *Defining Preferred Securities and Subordinated Debt*.

1 Mandatory weak triggers include minimum regulatory capital ratios set at low levels.

2 With restricted optional coupon skips, the issuer has to stop payment on parity or junior securities for more than six months before being able to skip hybrid coupon payments.

3 Optional and mandatory strong triggers include optional coupon-skip mechanisms and mandatory coupon suspension tied to the breach of strong or "meaningful" triggers, such as triggers that would be breached well in advance of a company-wide default.

4 The mandatory coupon suspension is non-cumulative; the optional coupon suspension can either be cumulative or non-cumulative.

Timing of Coupon Suspension

We expect that issuers generally will not opt to skip coupon payments unless they are close to a broad, company-wide default. Additionally, we think that the timing of coupon suspension will not be materially different between a non-cumulative and cumulative hybrid, nor is there much difference in terms of each security's ability to absorb losses and preserve liquidity. However, the addition of mandatory coupon suspension tied to the breach of strong or "meaningful" triggers, i.e., triggers that would be breached well in advance of a company-wide default, would generally result in more equity credit being given to a non-cumulative hybrid.

Depending on Their Strength, Triggers May Accelerate Coupon Suspension

We attribute more or less equity credit depending on the strength or weakness of mandatory coupon-skip triggers. Meaningful triggers are those that, if breached, result in the suspension of hybrid coupons and provide cash flow relief for issuers in a deteriorating financial condition. In these cases the triggers are typically set so that they would be breached just below the crossover point of the issuer/corporate family rating from investment-grade to speculative grade (typically at an issuer/corporate family rating of Ba1 or Ba2). In contrast, weak triggers would typically only be breached close to bankruptcy, resulting in minimal, if any, benefit for a going concern. Exhibit 3 shows a list of trigger types.

EXHIBIT 3

Trigger Type	Industry	Trigger Strength
Net loss	Insurance	Strong
Meaningful	As defined for insurers and corporates	Strong
Minimum regulatory capital	Insurance	Weak

MOODY'S INVESTORS SERVICE

Regulated Utility Sector Outlook Returns to Stable

Jillian Cardona, Analyst

Regulated utilities outlook returns to stable

Financial and cost recovery risks have decreased

- The outlook is stable based on our expectation for low natural gas prices, moderating inflation, few additional interest rate hikes and continued regulatory support.
- The sustained decline in natural gas prices in 2023 has eased both affordability pressures and regulatory risk.

State regulators, legislators remain supportive of utility credit quality

- Rate case outcomes have been more constructive than we had anticipated, considering high fuel charges on customer bills, costs incurred by utilities from extreme weather events, and the economic challenges facing utility customers.

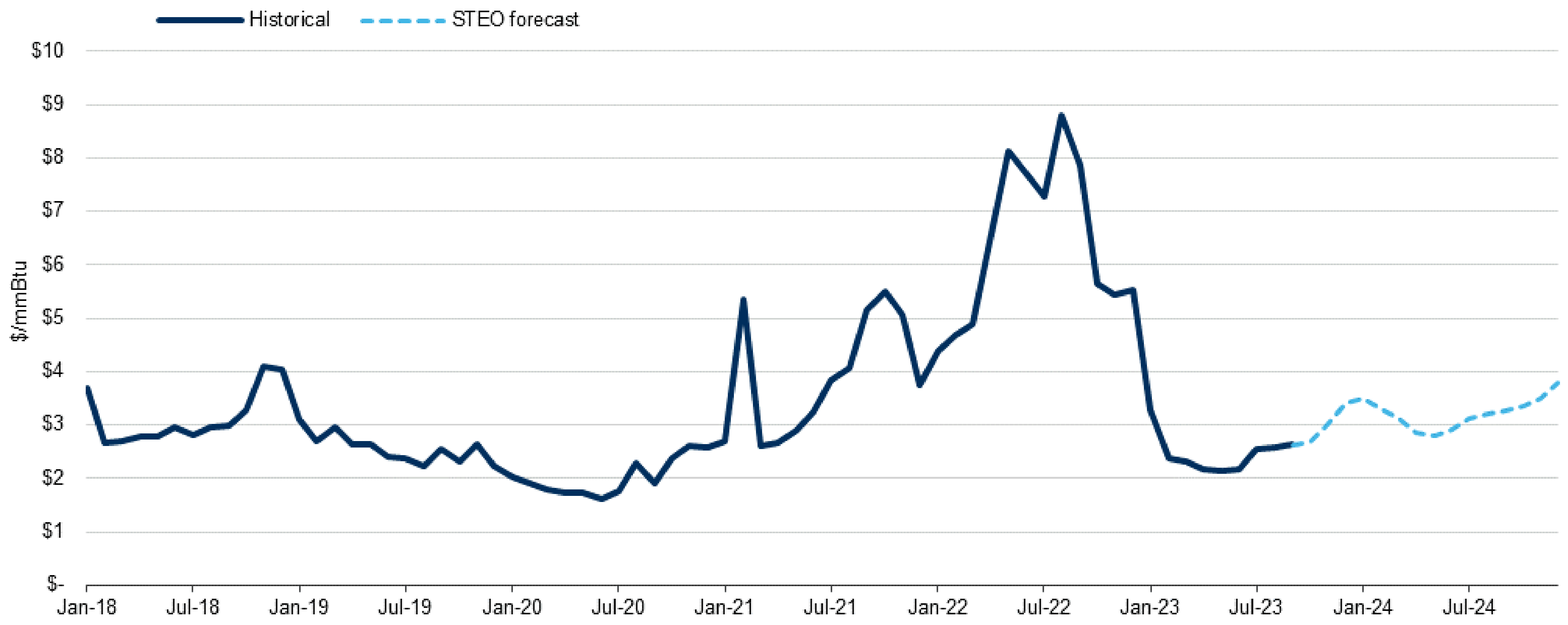
Higher interest rates and elevated capital spending will pressure holdco metrics

- The pace and magnitude of interest rate increases have slowed this year, but debt and debt refinancing costs have increased.
- We expect sustained high capex as utilities focus on reducing carbon emissions and investing in system resilience and reliability.

FFO-to-debt to stabilize while dividends continue to grow

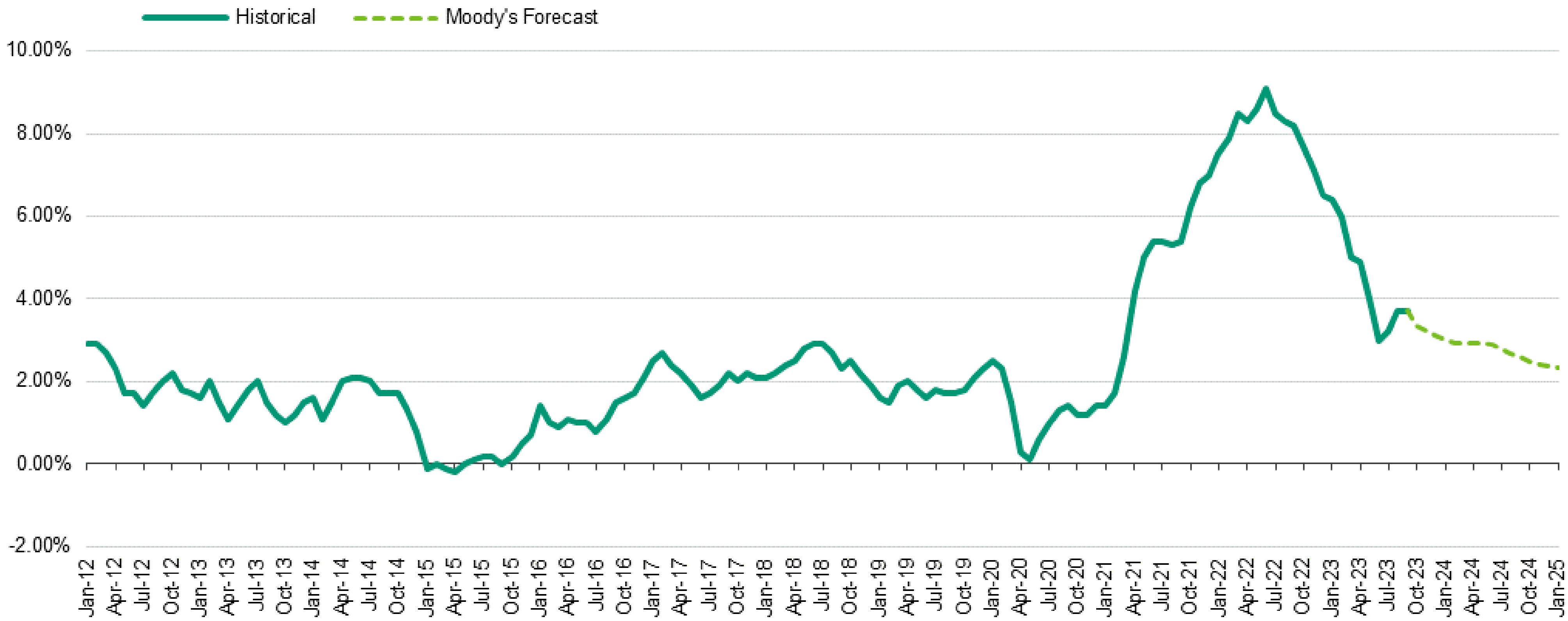
- We project the sector's aggregate ratio of funds from operations (FFO) to debt will remain stable at around 14%.
- Increased capital spending and dividends has led to rising negative free cash flow, which contributes to growth in total debt.

Henry Hub natural gas prices



Source: U.S. Energy Information Administration, Short-Term Energy Outlook, August 2023

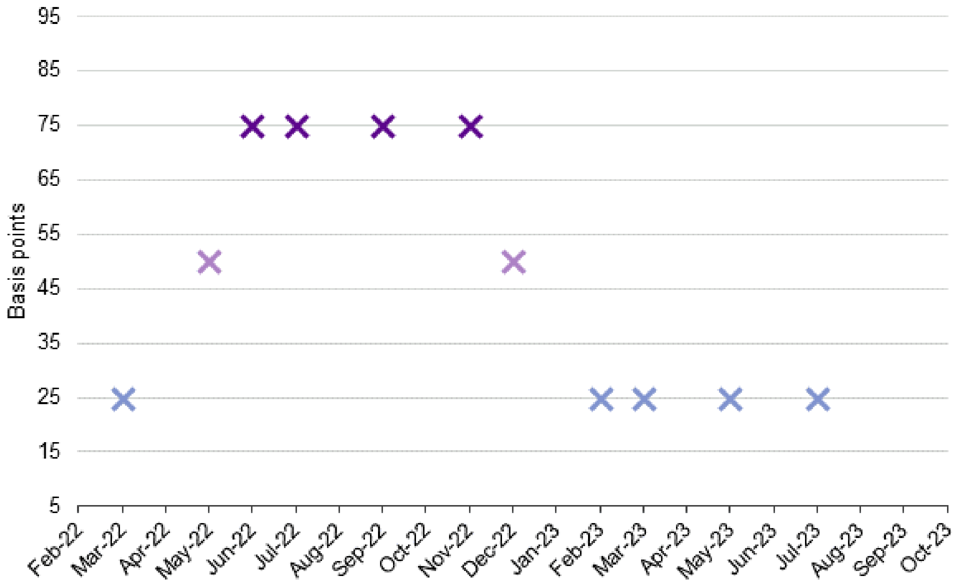
US Consumer Price Index (12 month % change)



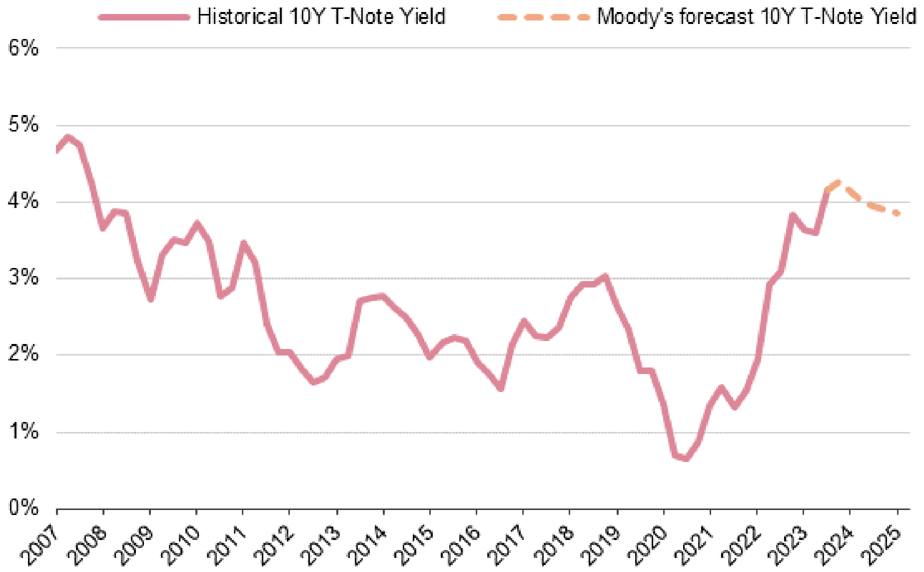
Sources: U.S. Bureau of Labor Statistics, Moody's Analytics Forecasted

US interest rates

Recent US Federal Open Market Committee interest rate increases (basis points)



Annual historical and projected ten-year treasury yield, 2007-2025F



Sources: U.S. Board of Governors of the Federal Reserve System; Moody's Analytics Forecasted

Most recent rate case outcomes have been supportive

New York State Electric & Gas

(Baa1 STA)

Rochester Gas & Electric

(Baa1 STA)

Central Maine Power

(A2 STA)

Consolidated Edison Company of New York

(Baa1 POS)

Arizona Public Service

(A3 NEG)

Tucson Electric Power

(A3 STA)

Pacific Gas & Electric

(Baa3*, POS)

Dayton Power & Light

(Baa3 STA)

Nova Scotia Power, a subsidiary of Emera

(Baa3 NEG)

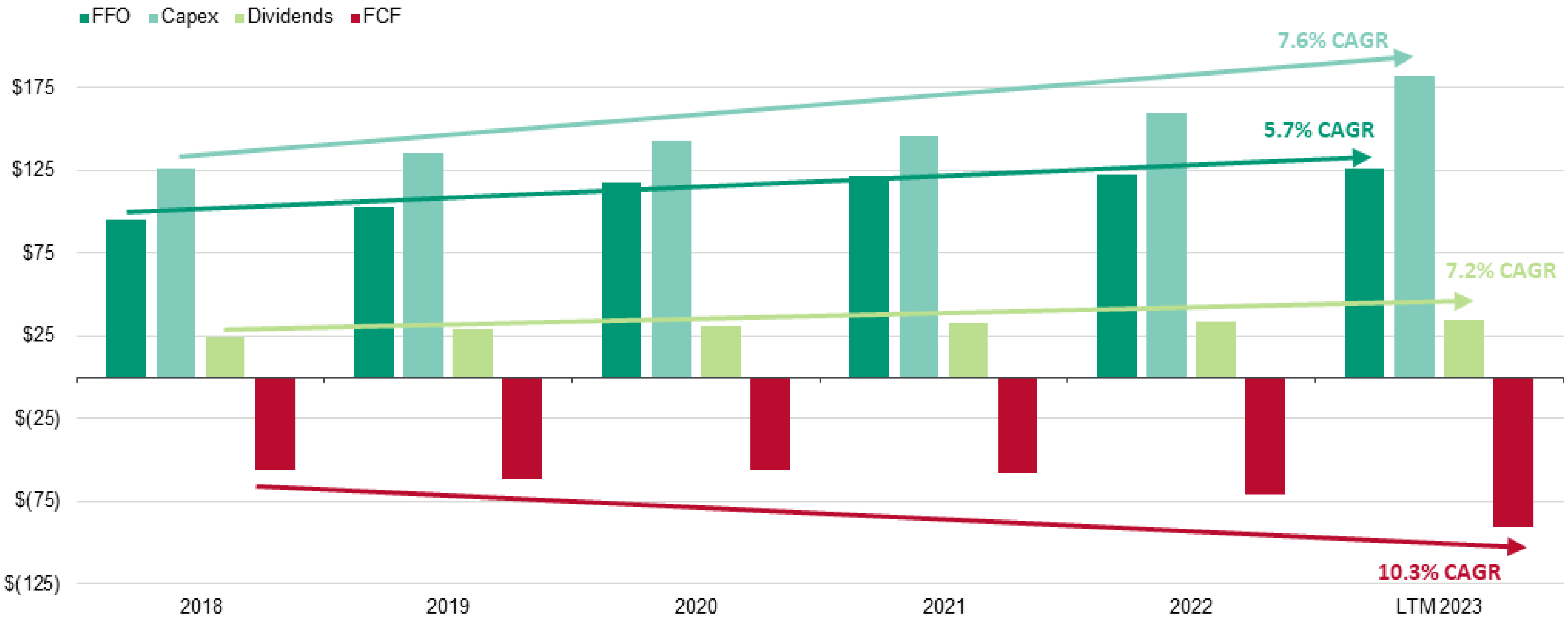
Oncor Electric Delivery Co.

(Baa1 STA)

Green – credit supportive   Yellow – mixed   Blue – still pending

* First mortgage bonds rating.

Capital spending and dividends can weigh on financial performance



Source: Moody's Financial Metrics™

Moody's Investors Service

Financial metrics remain weak, but strategic initiatives look to support credit quality

Ryan Wobbrock, VP - Sr. Credit Officer

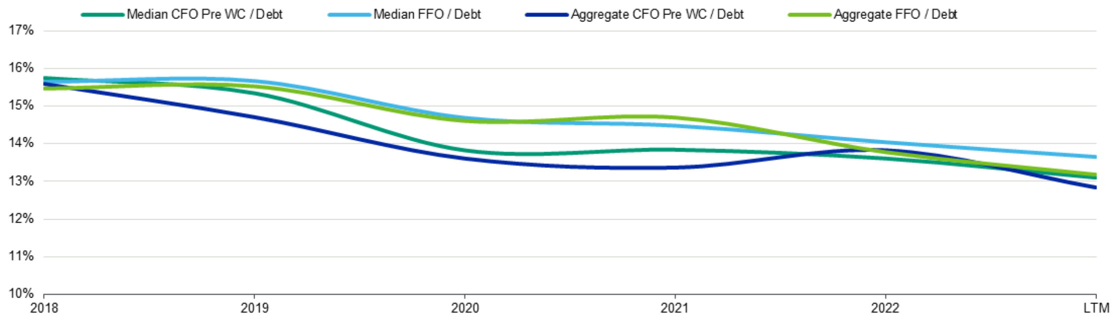
Topics

1. Weak financial metrics persist
2. We expect most metrics to improve
3. But financial policies threaten long-term sustainability

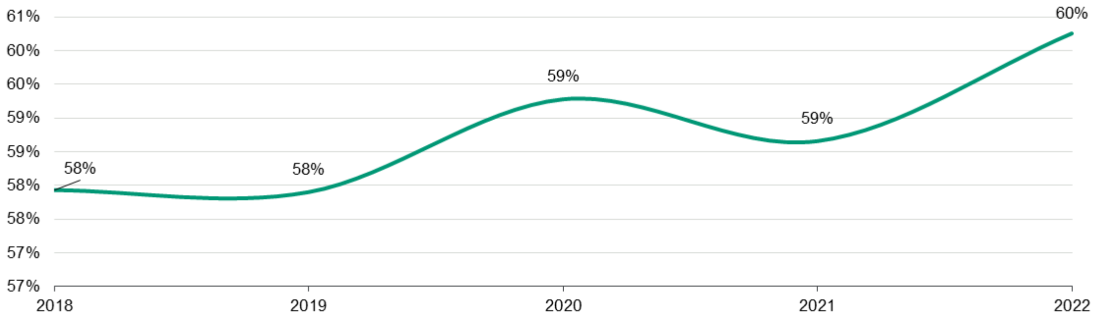
Over 40% of holdcos below metric thresholds

- » Cash flow growth has not kept pace with spending
- » Increasing leverage on assets
- » "Targeting threshold" strategies don't support unforeseen events

Cash flow to debt ratios have declined ~15% since 2018



Debt / Net PP&E has increased since 2018



Sources: Moody's Financial Metrics

We expect most companies' financials to rebound

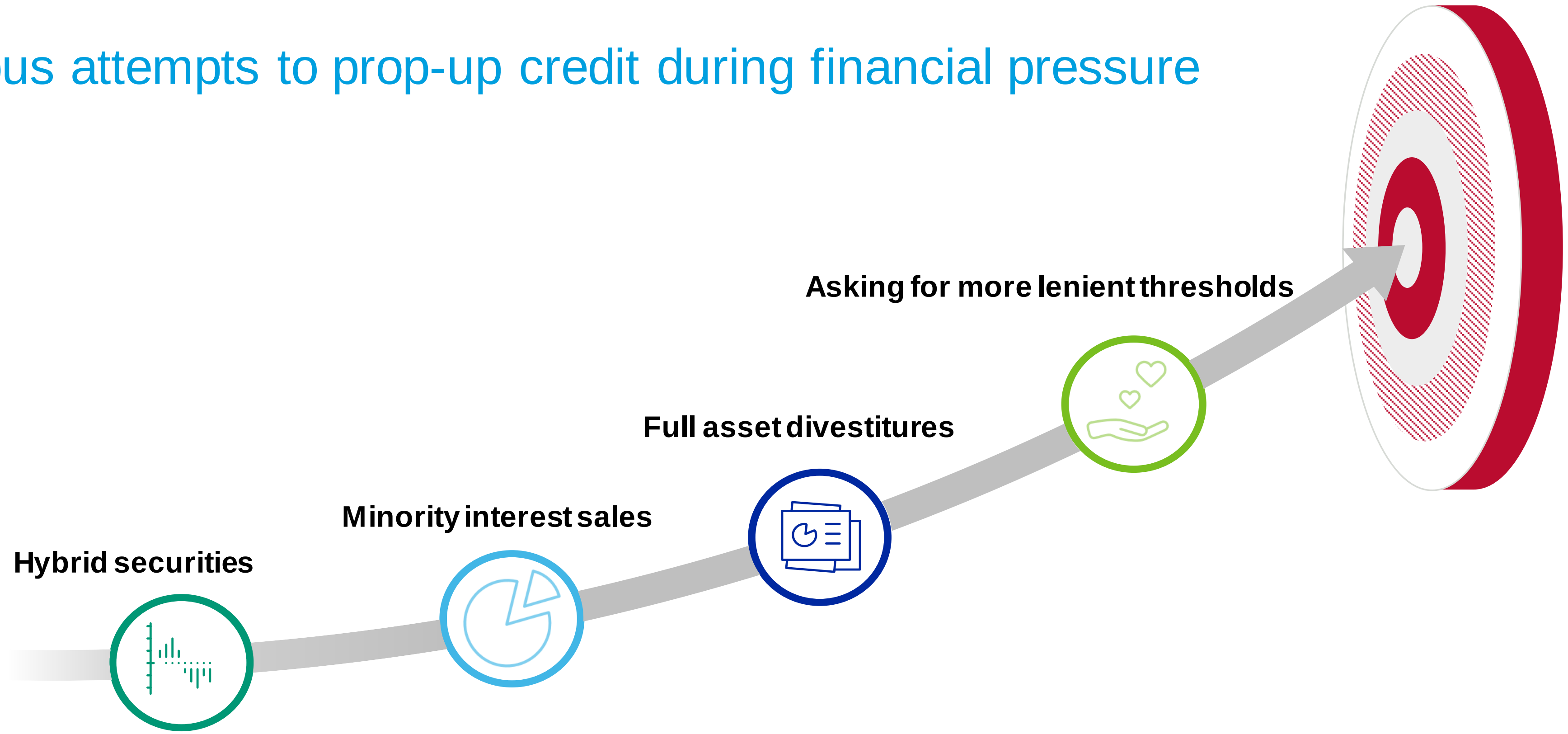
Organic improvement in cash flow, plus regulatory and legislative help

- Several one-time items affecting both CFO and debt trends
- Regulators are providing rate increases
  - ~ $5.0 billion of incremental revenue allowed in 2023 orders (incl. riders) alone
- Legislation helping when/where necessary
  - Securitization, riders

Many companies need extra help to improve

Strategic initiatives have become increasingly necessary

Various attempts to prop-up credit during financial pressure



Sustainable metrics require new financial policies

Temporary fixes won't support long-term FCF deficits funded by debt

Best defense is a good offense – proactive "levers" to aid credit

» Reduce parent debt and save on higher interest expense

» Slow the pace of capital spending

» Curb dividend growth

» Plan to have cushion against downgrade threshold

» Issue more common equity

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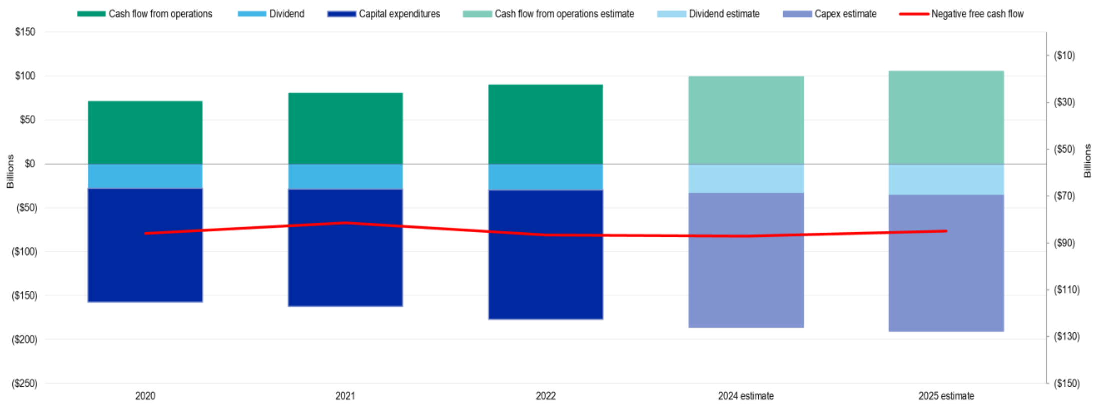
Rising capital expenditures will require additional equity funding

Jairo Chung, VP - Sr. Credit Officer

Utilities will need at least $25 billion in equity

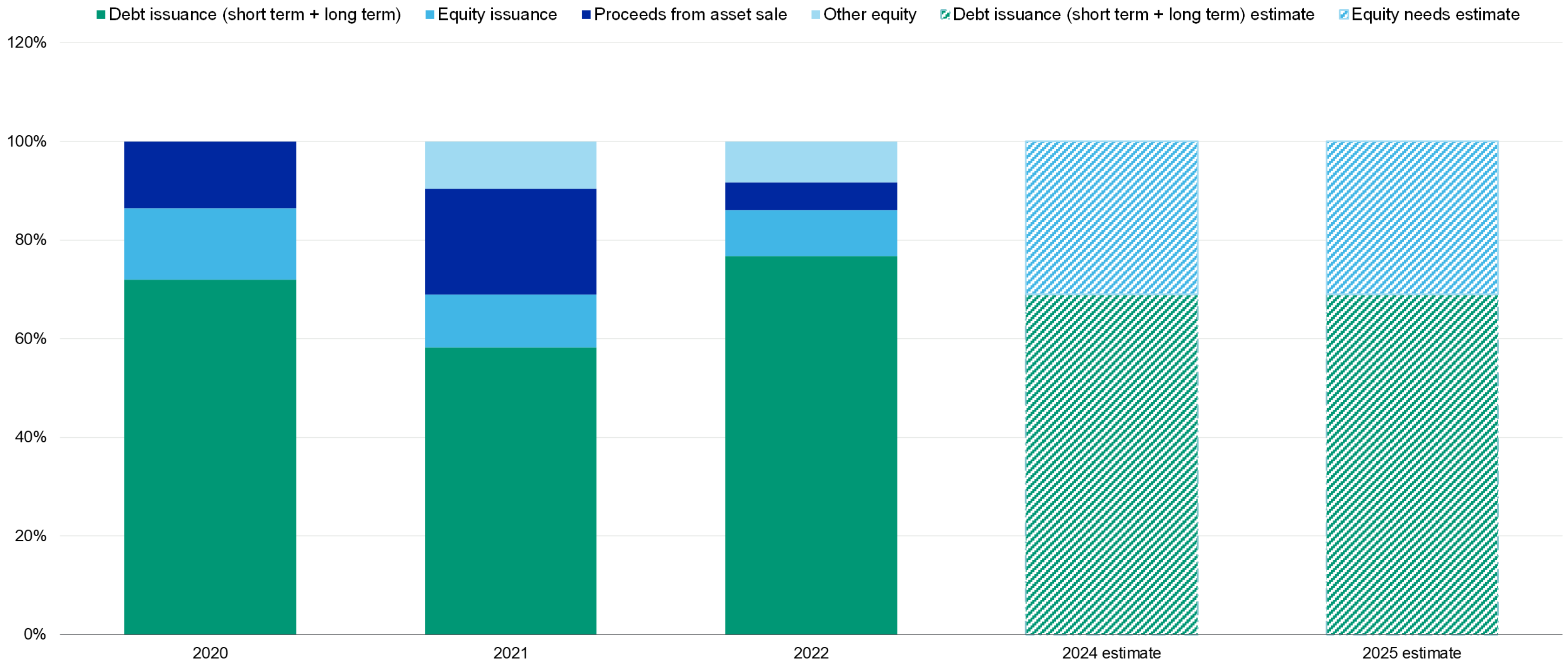
Based on 28 holding companies with annual capital expenditure greater than $1 billion

- Total aggregate annual investment to range from $150 billion to $155 billion in 2024 and 2025
- Assuming 6% CAGR of income, cash flow from operations estimated to average around $102 billion in the same period
- Negative free cash flow expected to be more than $85 billion per year
- If the funding mix remains at a similar level (70% debt / 30% equity), approximately $25 billion of equity is expected



Negative free cash flow to be funded primarily with debt

Equity funding averaged $15 billion* in 2020 - 2022



*Excluding the proceeds from the sale of PPL Corp.'s Western Power Distribution plc in 2021.

Asset sales remain the preferred option for equity raise

- Approximately $13 billion of equity was raised through asset sales over the18 month period ending June 30, 2023
- Several transactions that will result in a large equity raise expect to close over the next 18 months
- Regulatory support will contribute to higher earnings and cash flow
- Will we see more companies announcing common equity issuance in 2024?

Company	Transaction	Proceeds (in millions)	Status
American Electric Power, Inc.	Non-core, non-utility assets divestitures (including small transmission projects, renewable projects)	$943	Announced, expect to complete throughout 2024
Dominion Energy, Inc.	Sale of three regulated gas utility subsidiaries	$9,000	Announced
Dominion Energy, Inc.	Sale of 50% noncontrolling interest in the Cove Point LNG export facility	$3,000	Closed in September 2023
Duke Energy Corp	Sale of utility-scale renewable project and distributed generation business	$1,359	Utility-scale renewable project sale completed in October 2023; $259 million distributed generation business sale pending
Eversource Energy	Divestiture of offshore wind projects	$625	Announced and ongoing; $625 million sale of uncommitted lease area completed
FirstEnergy Corp.	Additional sale of FET equity ownership, decreasing its ownership from 80.1% to 50.1%	$3,500	Announced, 1Q24 closing expected
NiSource Inc.	Sale of 19.9% equity ownership in NIPSCO	$2,150	Announced, YE 2023 closing expected
PG&E Corp.	Potential sale of up to 49.9% of non-nuclear generating assets	TBD	Announced

Moody's
INVESTORS SERVICE

Assessing wildfire credit risk among western investor-owned utilities

Toby Shea, VP - Sr. Credit Officer

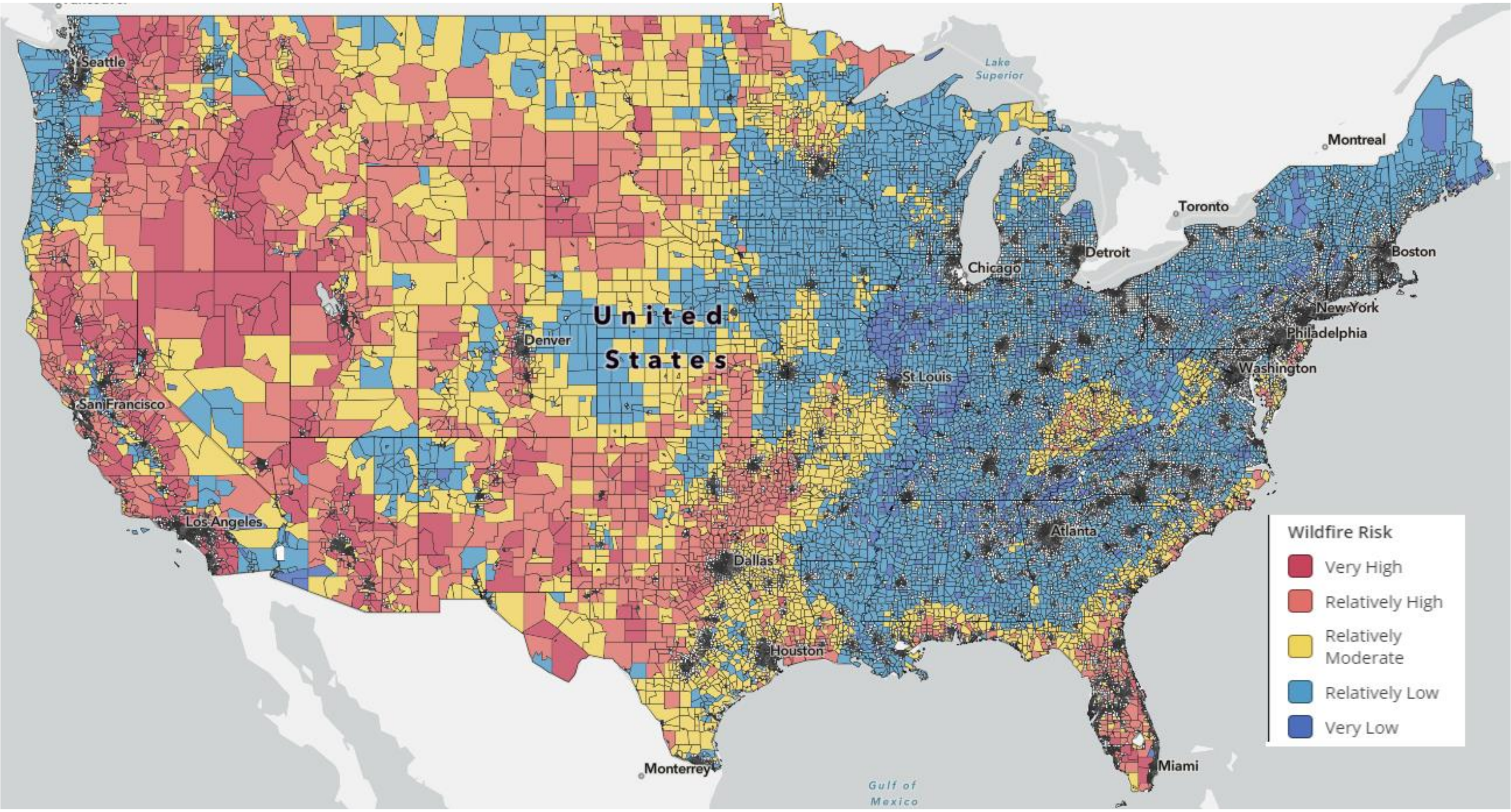
Nati Martel, VP – Sr. Analyst

1 Update on wildfire risks

Catastrophic wildfire risk is not limited to California

- 2017/2018 SCE and PG&E
- 2020 PacifiCorp in Oregon
- 2023 Hawaiian Electric in Maui
- Subsequent negligence lawsuits in OR and HI
- OR & HI not related to inverse condemnation

Large regions are at very high or relatively high risk



Source: FEMA – National Risk Index/ Maps https://hazards.fema.gov/nri/map

Difficult to pin down which utilities are most at risk

- Those with large areas with high or very high risk
- Oregon and Hawaiian fires were in moderate risk zones
- More of a problem in West but could be nationwide issue
- Risk can reach catastrophic levels at utilities
- Climate change: Hotter and drier but can also lead to fast, unexpected changes

Negligence lawsuits

- Jury trials with sometimes heart-wrenching testimony
- Multibillion dollar corporate defendant
- Easy to second guess and light burden of proof
- Potentially large pain & suffering and punitive damages
- Any payout at the end of long and drawn-out litigation
- Loss recovery through rates is difficult if found negligent

Protecting utilities legally and financially

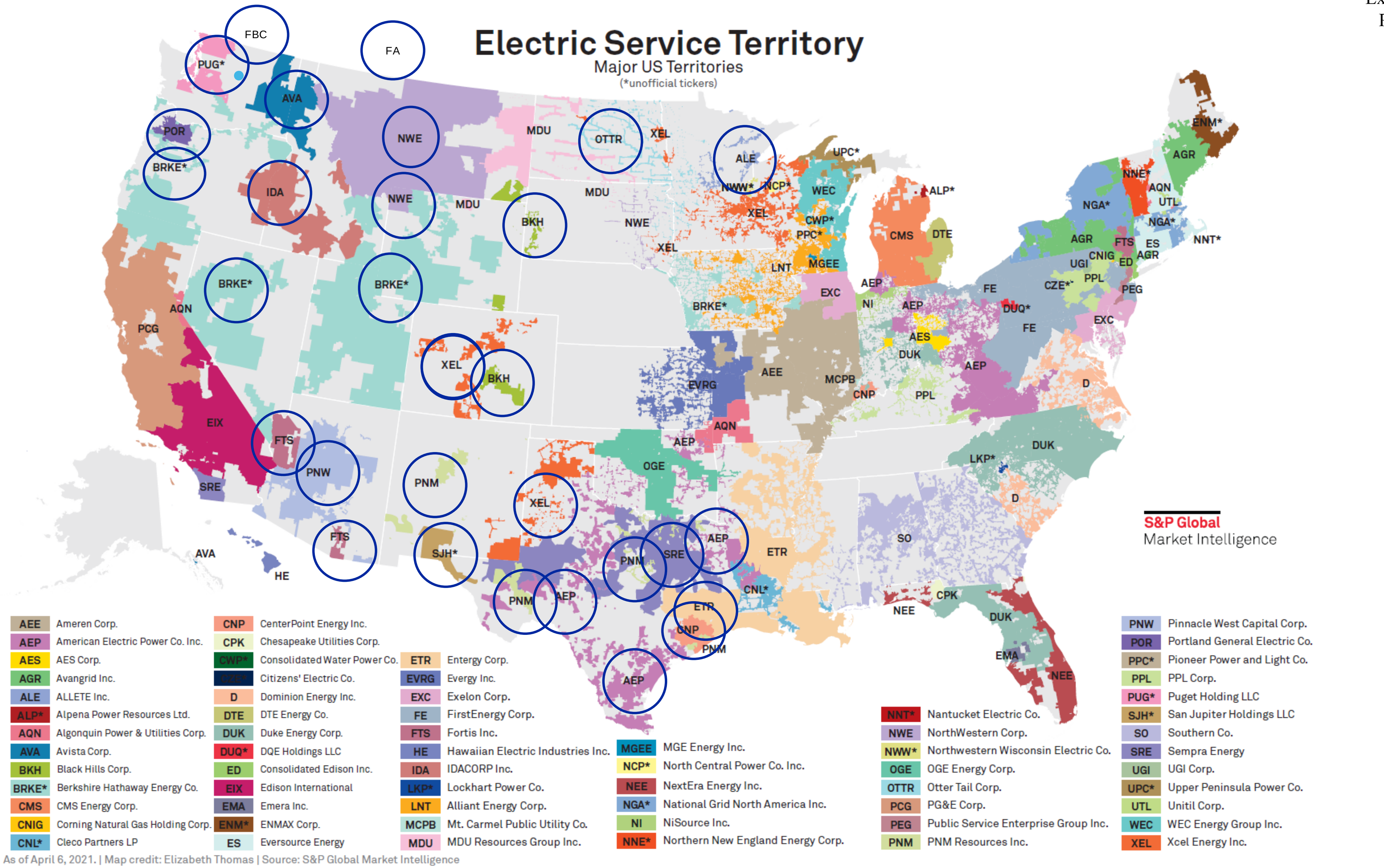
- Reducing litigation exposure
  - Clear policies and procedures reduce second-guessing
  - Statutory limitation on non-economic damages
- Reducing financial risk
  - Liability insurance, thru third-party provider or self-insurance
  - Utility-specific wildfire funds, similar to storm funds
  - State-wide wildfire funds, similar to the one in California

2

Key Factors Considered in Utility Wildfire Risk Analysis

Key Factors Considered

- Percentage of T&D lines in high wildfire risk areas
- Percentage of utility grid underground
- Wildfire history in service territory
- Number and extent of utility caused wildfires
- Wildfire related lawsuits/judgements/financial awards
- Wildfire mitigation plans
- Public safety power shutoff policy (current and planned)
- Spending on wildfire risk mitigation
- Insurance
- Liability standard in state


Electric Service Territory
Major US Territories
(*unofficial tickers)
S&P Global
Market Intelligence
AEE Ameren Corp.
AEP American Electric Power Co. Inc.
AES AES Corp.
AGR Avangrid Inc.
ALE ALLETE Inc.
ALP* Alpena Power Resources Ltd.
AQN Algonquin Power & Utilities Corp.
AVA Avista Corp.
BKH Black Hills Corp.
BRKE* Berkshire Hathaway Energy Co.
CMS CMS Energy Corp.
CNIG Corning Natural Gas Holding Corp.
CNL* Cleco Partners LP
CNP CenterPoint Energy Inc.
CPK Chesapeake Utilities Corp.
CWP* Consolidated Water Power Co.
CZE* Citizens' Electric Co.
D Dominion Energy Inc.
DTE DTE Energy Co.
DUK Duke Energy Corp.
DUQ* DQE Holdings LLC
ED Consolidated Edison Inc.
EIX Edison International
EMA Emera Inc.
ENM* ENMAX Corp.
ES Eversource Energy
ETR Entergy Corp.
EVRG Evergy Inc.
EXC Exelon Corp.
FE FirstEnergy Corp.
FTS Fortis Inc.
HE Hawaiian Electric Industries Inc.
IDA IDACORP Inc.
LKP* Lockhart Power Co.
LNT Alliant Energy Corp.
MCPB Mt. Carmel Public Utility Co.
MDU MDU Resources Group Inc.
MGEE MGE Energy Inc.
NCP* North Central Power Co. Inc.
NEE NextEra Energy Inc.
NGA* National Grid North America Inc.
NI NiSource Inc.
NNE* Northern New England Energy Corp.
NNT* Nantucket Electric Co.
NWE NorthWestern Corp.
NWW* Northwestern Wisconsin Electric Co.
OGE OGE Energy Corp.
OTTR Otter Tail Corp.
PCG PG&E Corp.
PEG Public Service Enterprise Group Inc.
PNM PNM Resources Inc.
PNW Pinnacle West Capital Corp.
POR Portland General Electric Co.
PPC* Pioneer Power and Light Co.
PPL PPL Corp.
PUG* Puget Holding LLC
SJH* San Jupiter Holdings LLC
SO Southern Co.
SRE Sempra Energy
UGI UGI Corp.
UPC* Upper Peninsula Power Co.
UTL Unitil Corp.
WEC WEC Energy Group Inc.
XEL Xcel Energy Inc.
FBC
FA
As of April 6, 2021. | Map credit: Elizabeth Thomas | Source: S&P Global Market Intelligence

% of T&D System in High Wildfire Areas/Zones

Why it matters

- Provides a broad indication of relative risk among individual utilities and their potential exposure to outages and damages related to wildfires.
- Suggests how much additional monitoring and oversight is required via physical inspection, cameras, drones, and other methods.
- May require a higher amount of capital expenditures for vegetation management, inspections and system hardening.

Analytical issues

- Does not fully factor in proximity to homes, businesses and population centers.
- Large portions of transmission system may be in remote areas, especially in less populated western states.
- Lack of consistency in the definition of what constitutes high wildfire risk areas.
- Some utilities referenced a standard hazardous area classification system: Zone 0: Explosive atmosphere for more than 1000h/yr. Zone 1: Explosive atmosphere for more than 10, but less than 1000 h/yr. Zone 2: Explosive atmosphere for less than 10h/yr.

Avista Corp Wildfire Risk Map

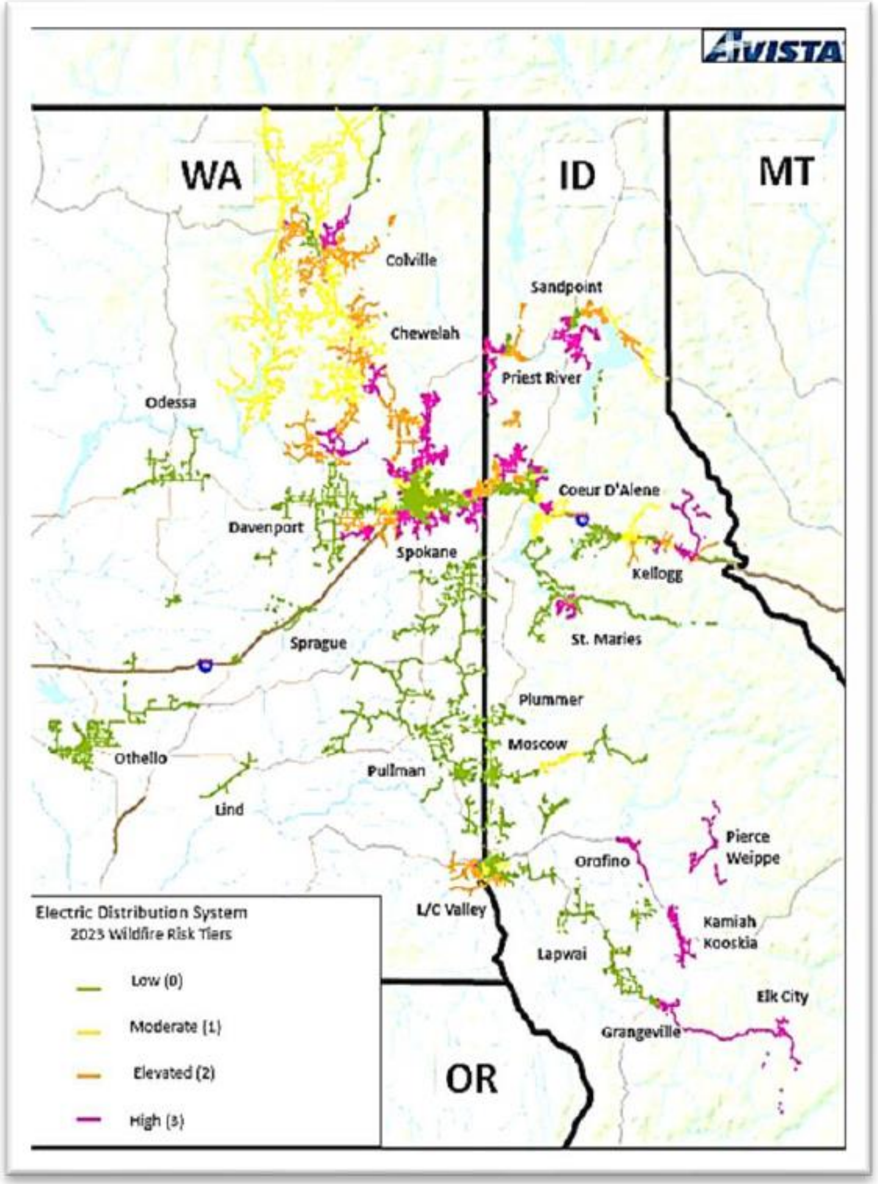
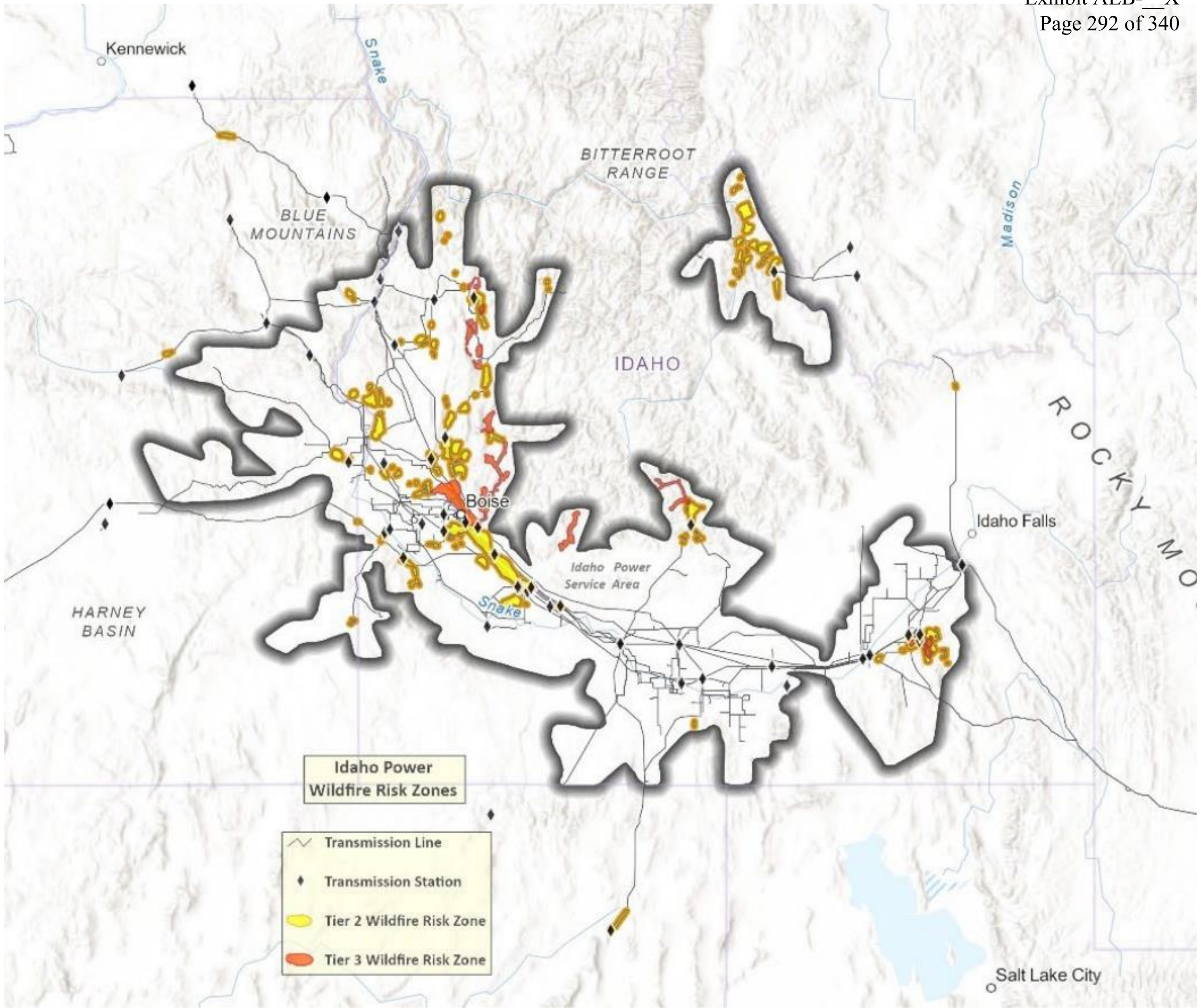
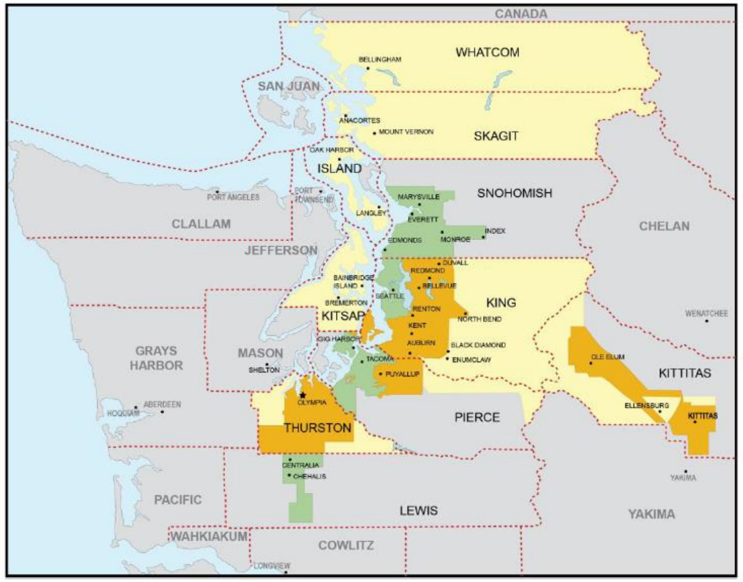


Figure 8. Avista's 2023 WUI Map

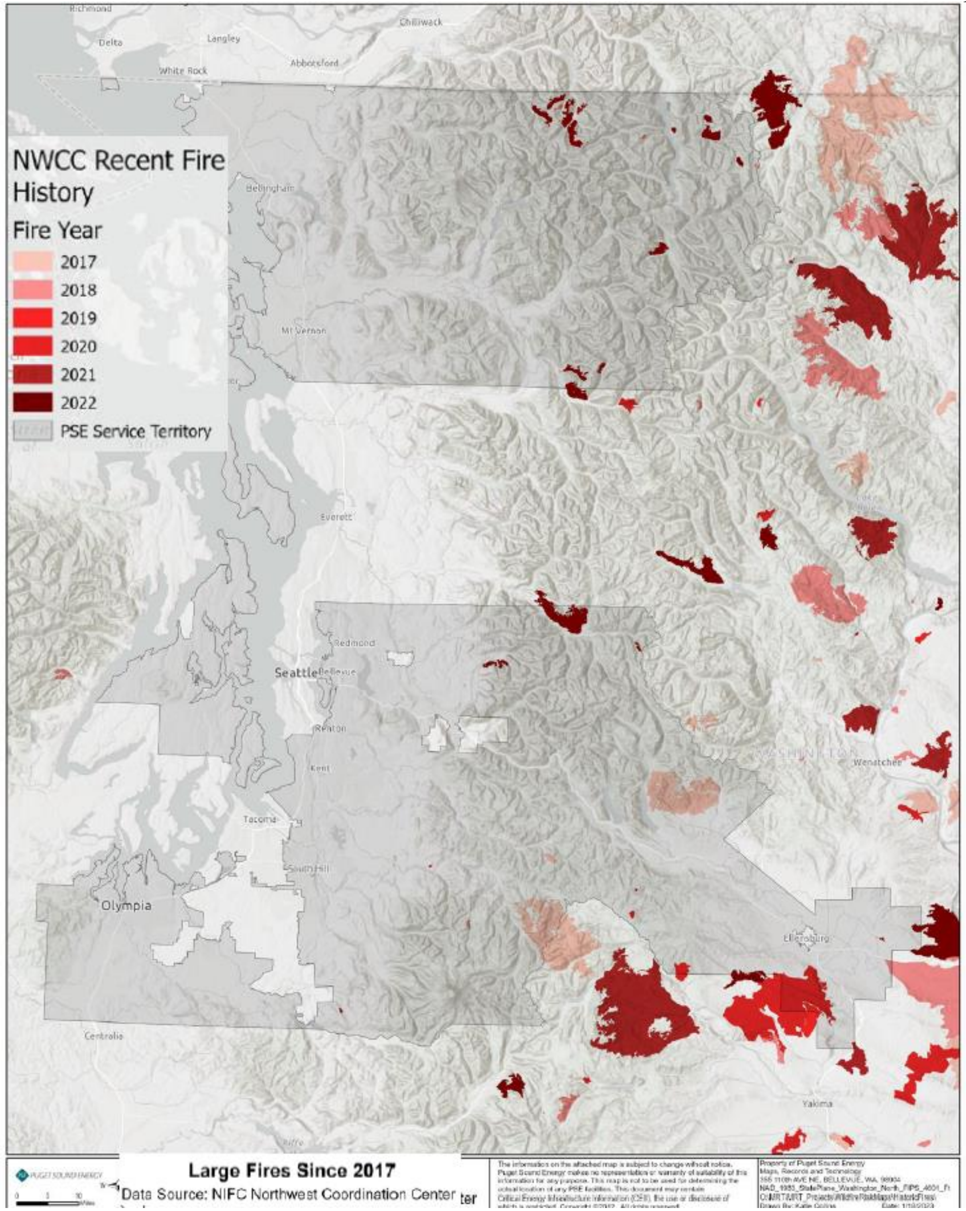
Idaho Power
Wildfire Risk Map



Puget Sound Energy Wildfire Risk Map



Combined electric and natural gas service
Electric service
Natural gas service
Public Utility Districts



% of T&D System Underground

Why it matters

- Burying power lines underground is widely considered to be among the most effective ways of reducing wildfire risk.
- In California, PG&E has indicated that undergrounding power lines reduces the chance that it will cause a wildfire by 99% because lines would be unaffected by wind, the key contributor.
- As a result, the percentage of a utility T&D system underground should be a good indicator of its progress in reducing wildfire risk.

Analytical issues

- Undergrounding power lines is among the most expensive, time-consuming wildfire responses with costs ranging from $2 to $6 million per mile, up to 10 times the cost of overhead lines.
- Partially because of the cost, insulating overhead power lines by using “covered conductors” to prevent wildfire ignition is being used by some utilities, such as Southern California Edison.
- Some utilities have expressed a reluctance to use covered conductors for various reasons, including their weight and a lower ability to detect faults or other electrical disturbances.
- More concentrated, smaller footprint utilities may have an advantage in undergrounding.

Challenges in undergrounding T&D system (PG&E)

As companies bury power lines, consumers dig in against high rates

The CEO of Pacific Gas & Electric says the company has a "moral obligation" to prevent wildfire risk after their equipment sparked blazes in the past. The company wants to bury power lines, but California regulators balk at the price and lengthy process. **By Adam Beam** Associated Press

October 17, 2023|**VACAVILLE, CALIF.**

Pacific Gas & Electric – one of the nation's largest utilities whose equipment has sparked some of California's deadliest wildfires – wants to bury power lines in some of its most at-risk areas to prevent destructive blazes like the 2018 Paradise fire that killed 85 people.

But state regulators are balking at the utility's plan because it would take too long and cost $5.9 billion. The company's customers – who already have some of the highest rates in the country – would have to pay for it.

Regulators want PG&E to put a protective cover over many of its overhead power lines instead of burying them. The cover approach is cheaper, but riskier. PG&E says burying a power line reduces the chance it will start a wildfire by 99% because it can't be blown down by windstorms. The protective cover, which would better insulate the power line should it fall to the ground, would reduce that chance by 62%.

"We're not going to live with 35% risk," said PG&E CEO Patti Poppe, who was rounding down in her assessment. "Who wants to get on a plane that has a 35% chance of crashing?"

PG&E, which filed for bankruptcy protection in 2019 after it faced more than $30 billion in damages for wildfires started by its equipment, is trying to convince regulators that its burying plan is better. The company filed its plan with state regulators last year.

The California Public Utilities Commission, whose members are appointed by Gov. Gavin Newsom, is scheduled to decide the issue in November. PG&E will make its case in person before the commission Oct. 18.

Wildfire History/Utility Caused Fires

Why it matters

- While wildfire risk is increasing due to climate change, a history of wildfires can indicate that a utility is already more vulnerable to such events.
- It could also be an indication of how experienced or prepared a particular utility is to address, respond to and fight wildfires.
- In California, San Diego Gas & Electric's experience with the 2007 wildfires put it well ahead of its two peer California utilities in wildfire protection, monitoring and sophistication.

Analytical issues

- Materiality judgements affected utility responses to our queries as most reported they had experienced no material wildfires.
- Some utilities also indicated they did not track all wildfires in their service territory, only those where their equipment is involved.
- In the few exceptions, Arizona Public Service reported 2,400 fires annually and there were 600 fires annually in NorthWestern's service territory, which may suggest a higher level of situational awareness and sophistication on the part of these utilities.

Judgements/Verdicts Related to Wildfires

Why it matters

- One indication of potential future financial liability risk related wildfires.
- Could be a signal that the legal or regulatory environment in which a utility operates results in more liability risk.
- To determine if any utilities are subject to potentially substantial liabilities that might be similar to the state of California's unique application of inverse condemnation to investor-owned utilities.

Analytical issues

- Responses indicate that utilities have rarely been subject to material legal judgements or financial awards related to wildfires.
- The few that have paid claims have typically settled for nominal amounts well after the wildfire event in question.
- However, in an unusual development earlier this year, an Oregon state court jury found PacifiCorp liable, including gross negligence, and awarded 17 plaintiffs $90 million of damages for causing a wildfire. This class action lawsuit has the potential to create a substantial litigation liability for PacifiCorp because the entire class could eventually have over 1,000 plaintiffs.

Annual Spending Related to Wildfire Mitigation

Why it matters

- Spending designated for wildfires provides information on both whether a utility is exposed to wildfires and how seriously it is addressing the risk.
- If specific spending for wildfire prevention and mitigation is approved by state regulators, these regulators may be more supportive of cost recovery for damages and repairs after a wildfire.
- We view regulatory approval of such spending positively as it puts the regulator in a position of signing off and in some cases endorsing such plans.

Analytical issues

- Several utilities do not segregate or designate specific wildfire spending in their capital expenditure plans.
- Others have indicated that it is included in their overall grid resiliency, hardening and vegetation management capital spending programs.
- This is understandable for those utilities considered at low risk for wildfires in most of the categories we analyzed, as we would not expect wildfire spending to be specifically designated.

Wildfire Mitigation Plans

Wildfire mitigation plans (WMP's) aim to limit the potential that utility T&D systems contribute to or cause wildfire ignition. In California, they describe how a utility is constructing, maintaining, and operating its electrical lines and equipment in a manner that will minimize catastrophic wildfire risk.

Why they matter

- The filing of annual wildfire mitigation plans have been required of utilities in California as a key method for ensuring that adequate measures are being taken to lower the risk of wildfires in that state. Plans are also filed in Colorado, Oregon and Washington.
- Approval of such plans by regulators provides an endorsement and gives regulators an incentive to support the utilities if they seek recovery from costs incurred from wildfires that do occur.
- Regulatory approval of the California plans is required for those utilities to access their annual wildfire safety certificate which gives utilities access to the state wildfire insurance fund.

Analytical issues

- Some utilities include wildfire mitigation in their overall grid hardening and resiliency spending.
- Several utilities have not provided a copy of their WMP's, with a few citing confidentiality.
- Which utilities are at sufficient risk that they should have a formal WMP?

Public Safety Power Shutoffs (PSPS)

A Public Safety Power Shutoff (PSPS) is an operational practice an electric utility can use to temporarily shut off power to help prevent wildfires during extremely hot, dry and/or windy weather conditions. They are widely considered to be a measure of last resort in preventing wildfires.

Why they matter

- California regulators approved implementation for the three major IOU's between 2013 and 2018.
- After a controversial and widely unpopular execution in 2019 with 19 PSPS events, they have become a more targeted and effective tool for utilities in that state to prevent wildfires.
- They have now been formally implemented in at least two other states (Nevada and Oregon).
- Both PacifiCorp and Hawaiian Electric have been criticized and ultimately sued for allegedly not shutting off power in advance of 2020 Oregon and 2023 Maui wildfires, respectively.

Analytical issues

- Some local communities and firefighters oppose the use of PSPS because it hampers the effective fighting of wildfires by preventing water pumps and other equipment from functioning.
- It is important that transparent policies, procedures and communication protocols be specifically delineated to ensure that the utility is not criticized or second guessed after implementing a PSPS.
- Unlikely to be widely implemented in areas where wildfires are not a material risk.

PSPS has been widely adopted in California…

PUBLIC SAFETY POWER SHUTOFF

All Californians should be prepared for potential power outages.

When will a Public Safety Power Shutoff occur?

Fire is, and always has been, a natural part of living in our beautiful state. Unlike most natural disasters, wildfires are often started by people. During dry weather and droughts, normally green vegetation can convert into flammable fuel; strong winds spread fire quickly; and warm temperatures encourage combustion. With these ingredients, the only thing missing is a spark—in the form of lightning, a downed power line, a spark from a lawn mower, a burning campfire or cigarette—to wreak havoc.

Every situation is unique. Your energy company makes the decision to turn off power by monitoring local fire danger conditions across California and taking into consideration a combination of weather and environmental factors.

If extreme fire danger conditions threaten a portion of the electric system serving your community, it may be necessary for PG&E to turn off electricity in the interest of public safety. This is called Public Safety Power Shutoff.

Sign up for updates related to Public Safety Power Shutoffs here, and learn more about if where you live might experience a shutoff: www.pge.com/mywildfirealerts

More information is available at: www.pge.com/en_US/safety/emergency-preparedness/natural-disaster/wildfires/public-safety-power-shutoff-faq.page

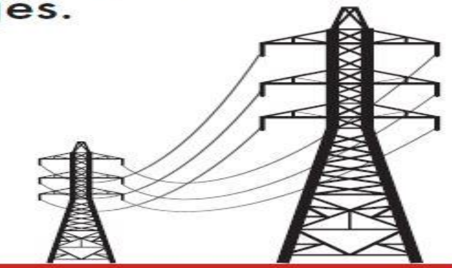
If a Public Safety Power Shutoff is needed due to extreme weather conditions, you can expect:

EARLY WARNING NOTIFICATION – Your energy company will aim to send customer alerts before shutting off power.

ONGOING UPDATES – Your energy company will provide ongoing updates through social media, local news outlets and their website.

SAFETY INSPECTIONS – After extreme weather has passed, your energy company will inspect the lines in affected areas before power is safely restored.

POWER RESTORATION – Power outages could last multiple days depending on the severity of the weather and other factors. It is important that you and your family have an emergency preparedness plan in place.



PUBLIC SAFETY POWER SHUTOFF MAY OCCUR DUE TO THE FOLLOWING FACTORS:

- HIGH WINDS AND HIGH WIND GUSTS
- LOW HUMIDITY LEVELS
- DRY VEGETATION that could serve as fuel for a wildfire
- FIRE THREAT to electric infrastructure
- REAL-TIME OBSERVATIONS by on-the-ground field experts
- RED FLAG WARNING declared by the National Weather Service

7.20

…but not without controversy, particularly in 2019

PG&E's power shutoff in California shows the inequities of climate risks

More than 800,000 customers could lose power as California's largest utility tries to avoid igniting another wildfire.

By Umair Irfan   Updated Oct 10, 2019, 2:16pm EDT

Power remains out for hundreds of thousands of Pacific Gas & Electric customers in California on Thursday after the utility shut down power to more than 500,000 customers early Wednesday morning, with more outages likely in the coming days.

It's a drastic and controversial move to avoid sparking a fire and it's already impacted the lives and livelihoods of millions.

"I'm outraged, because it didn't need to happen," California Gov. Gavin Newsom said on Wednesday. "[PG&E are] in bankruptcy because of their terrible management going back decades ... They created these conditions."

PG&E, which serves more than 16 million people, saw its website crash with traffic. The company was directing customers to an alternative site for more information about the outages on Wednesday evening. (Our sister site Curbed has a list of all the areas affected by the power shutdown). By Thursday morning, some areas affected by the blackout started to receive power.

Meanwhile fire crews battled small fires throughout California through Wednesday night, and the northern part of the state remains on high alert for wildfires.

The forced blackout is a blunt response to the growing risks of disastrous wildfires brought about by a complex combination of suburban sprawl, poor land management practices, and climate change. And it's a stark example of the trade-offs that come from adapting to a warmer world.

The utility is calling this a Public Safety Power Shutoff (PSPS); the concern is that high winds could knock trees over into power lines, shooting off sparks that hit a stretch of land primed to burn. This week, warm, dry weather, ample vegetation, and strong seasonal Diablo winds that can gust at 70 mph have created the "recipe for explosive fire growth," according to the National Weather Service.

Insurance for Wildfires

Why it matters

- Insurance provides a degree of financial protection against wildfire costs.
- Most wildfire events have resulted in damages that have been easily covered by insurance.
- The aggregate amount of insurance is an indication of how much cushion a utility has before its financial condition would be affected by wildfire liabilities.

Analytical issues

- Many utilities do not have insurance specifically designated for wildfires, but damages would be covered under master liability and property limits.
- Transmission and distribution systems themselves are not covered by insurance, although power plants, substations and other buildings are.
- The industry has begun calling for a nationwide or state-run insurance or natural disaster fund similar to what is in place in some places for hurricanes, flooding, and nuclear disasters.
- As part of California's wildfire mitigation reforms, the state established an insurance fund for wildfires, among the most important factors supporting the credit quality of utilities in the state.

Negligence Standards/Inverse Condemnation

Under “inverse condemnation” as it is currently applied in California, investor-owned utilities are held strictly liable for damages from fires that were caused by utility equipment, regardless of fault or the reasonableness of its conduct. Although not public entities, their infrastructure is publicly used.

Why it matters

- The potential that PG&E might be liable for nearly $30 billion of costs associated with major California wildfires in 2017 and 2018 was a key reason for its bankruptcy filing.
- Other states have inverse condemnation clauses as part of state law, although they are rarely applied to investor-owned utilities.
- Utilities typically legally address wildfires as negligence claims under tort law, which requires a higher burden of proof as the plaintiff has to prove that the defendant’s negligence directly led to the harm.

Analytical issues

- State limits on economic damages, non-economic damages or punitive damages regarding wildfire liabilities if found negligent or grossly negligent need to be considered.
- In June, an Oregon state court found PacifiCorp liable, including gross negligence, for 2020 fires and awarded 17 plaintiffs $90 million of damages, although this could multiply with additional plaintiffs.

Summary of outcomes and relative risk

Utility	% of T&D Lines in High Wildfire Areas	% of Grid Underground	Wildfire History	Utility Caused Wildfires - Last 10 Yrs	Judgements/ Verdicts	Annual Spending (% 2022 Capex)	Mitigation Plan/Copy?	PSPS/Utilized?	Overall Wildfire Risk
AEP Texas (Baa2)	0%	17%	No material fires	None	None	Not provided	No	Yes/No	Low
ALLETE (Baa1)	Low	28%	No material fires	None	None	$90 mm (40%)	No	No	Low
Arizona PS (A3)	18%	64%	26,100 acres or more	None material	None	$75 mm (5%)	Yes/Yes	In progress	High
Avista (Baa2)	35%	24%	Several	4	$16.5 mm	$50 mm (11%)	Yes/Yes	Yes/No	High
Black Hills (Baa2)	20-25%	25%	3 material fires	None	None	None designated	No	No	Low-to-Moderate
CenterPoint (Baa1)	Not provided	37%	No material fires	None	None	None designated	No	Yes/No	Low
Entergy Tx (Baa2)	25%	7%	Not tracked	1 in 10 years	$105,000	None designated	No	No	Moderate
FortisAlberta (Baa1)	18%	20%	10-16 fires annually	Limited	None material	CAD20 mm (4%)	Yes/No	No	Low
FortisBC (Baa1)	>50%	18%	2 material fires	None material	None	None designated	Yes/Yes	No	Low
Idaho Power (Baa1)	8%	28%	75 fires annually	None material	$1.5 mm	$40 mm (10%)	Yes/Yes	Yes/No	Moderate
NV Energy (Baa1)	11%	44%	Medium	Minimal	None material	$155 mm (10%)	Yes/Yes	Yes/Yes	High
NorthWestern (Baa2)	4.8% T/1.5% D	28%	600 fires annually	1	Litigation pending	$85 mm (17%)	Yes/Yes	No	Moderate
Oncor (Baa1)	Not public	25%	No material fires	None	None material	None designated	Yes/Yes	No	Low-to-Moderate
Otter Tail (A3)	0%	31%	No material fires	None	None	$11 mm (6%)	No	No	Moderate
PacifiCorp (A3)	9% in Fire High Consequence Areas	50% (FHCA)	Elevated	Various, all disputed	$90 mm verdict	$400 mm (20%)	Yes/Yes	Yes/Yes	High
Portland Gen (A3)	7%	59%	24 fires	None material	None	$76 mm (10%)	Yes/Yes	Yes/Yes	Moderate
PS of Colorado (A3)	36%	64%	Moderate to high	13	Complaints pending	$110 mm (7%)	Yes/Yes	No	Moderate
PS of NM (Baa2)	Not public	53%	Not public	Not public	None	None designated	Yes/Yes	No	Low
Puget Sound (Baa1)	< 3%	60%	Not tracked	None	1 pending	$25 mm (2%)	Yes/Yes	No	Low
Southwest PS (Baa2)	Not provided	7%	1,430 since 2014	54 since 2014	<$700,000	None designated	No	No	Low
TNMP (Baa1)	Not public	16%	Not public	Not public	None	None designated	No	No	Low

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S&P Capital IQ PRO

Ameren, Exelon shares fall after Illinois regulators reject grid plans

Friday, December 15, 2023 1:52 PM ET

By Allison Good
Platts

Shares of Ameren Corp. and Exelon Corp. each dropped more than 7% on Dec. 14 after Illinois regulators rejected multiyear grid plan proposals by their utility subsidiaries and authorized lower-than-expected equity returns beginning in January 2024.

The Illinois Commerce Commission determined the four-year electric distribution grid plans proposed by Ameren Illinois Co. and Commonwealth Edison Co. did not adequately describe community benefits, transparency, affordability or cost-effectiveness and did not comply with the state's Climate and Equitable Jobs Act (CEJA) of 2021.

"The Commission's decisions today protect Illinois ratepayers and the goals CEJA created. Illinois' utilities are specifically required to consider affordability and cost-effectiveness so that customers are not unfairly asked to shoulder undue costs tied to the state’s energy transition," ICC Chairman Doug Scott said in a statement. "While we are not yet at the finish line, compliant plans from the state's largest utilities will help lead us to an energy transition that works for all Illinoisans."

The law requires Illinois to transition to 50% renewable energy by 2040 and 100% clean energy by 2050 through reducing emissions and supporting electrification.

The commission also authorized an 8.72% return on equity (ROE) for Ameren Illinois (Docket No. D-23-0082) and an 8.91% ROE for Commonwealth Edison (ComEd) (Docket No. D-23-0055), a substantial decrease from the administrative law judge's recommended 9.24% ROE for Ameren Illinois and 9.28% ROE for ComEd. Both utilities originally asked for a 10.50% ROE.

"We can say at this time that we are very disappointed with the outcome," ComEd said in a Dec. 15 email. "That said, we remain committed to working with all stakeholders, including our regulators, to deliver a cleaner, more equitable, and brighter energy future for the northern Illinois communities we're privileged to serve."

Ameren did not immediately respond to requests for comment.

Both companies' stock prices continued to decline Dec. 15. In midday trading, Ameren shares were down about 3.5%, hovering below $72, and Exelon shares were down about 5%, trading below $36, both on above-average volume.

Unexpected regulatory decisions

Industry analysts told investors that the rulings were worse than anticipated.

"Even though we believe most investors' expectations were significantly dampened by the mid-November final orders in the Illinois gas utility rate cases, from our conversations, investor outlooks had coalesced around the 9.3% to 9.4% level [for ROE]," analysts at BMO wrote. "Which, given the sensitivity of [approximately 4 cents of earnings per share] per every 50 [basis points] change in ROE for both companies, in our opinion, could have resulted in a de-risking event."

"We expect a disproportionate effect on 2024 earnings for each company," they continued.

The utilities have three months to refile their grid plans, but KeyBanc analysts still anticipate a "messy and contentious" process with an "uncertain" timeline. "We believe that it will be difficult for Ameren, as well as its peer, to maintain their status as premium utilities," the analysts said.

Wells Fargo analysts agreed that the grid plan rejections jeopardize Ameren's and Exelon's targeted earnings per share compound annual growth rates and told clients they "now view [Illinois] as one of the worst regulatory jurisdictions in the US."

None of the analysts faulted the companies' management.

"We don't see this as a management issue — both teams have been good operators and worked through the case process to a manageable proposed order. ... the ICC is simply sending a negative message to investors," Guggenheim analysts wrote.

During a third-quarter earnings call on Nov. 9, Ameren President and CEO Martin Lyons said the company was hopeful the ICC would "reach a more constructive and fair outcome" given that the administrative law judge's calculations used "inappropriate data points."

S&P Capital IQ PRO

Exelon CEO Calvin Butler similarly criticized the law judge's decision during a Nov. 2 earnings call.

"The [proposed] order does not recognize a fair cost of financing that investment," Butler emphasized. "It provides a return on equity that is well below the national average. It does not recognize the significant investment we have made in our pension which supports ComEd's employees and has saved customers almost $1 billion to date with its returns and continues to generate savings for our customers, and it does not allow for a prudent capitalization of the business."

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UBS

Global Research and Evidence Lab
14 December 2023

First Read

Exelon Corp

Negative Rate Case Outcome - Rating and PT Under Review

Equities

Americas
Electric Utilities

12-month rating (UR)	**Buy ***
12m price target (UR)	**US$47.00**
Price (14 Dec 2023)	**US$38.00**
RIC: EXC.O **BBG:** EXC US	

Trading data and key metrics

52-wk range	US$44.15-36.61
Market cap.	US$37.9b
Shares o/s	997m (COM)
Free float	100%
Avg. daily volume ('000)	6,381
Avg. daily value (m)	US$250.3
Common s/h equity (12/23E)	US$25.9b
P/BV (12/23E)	1.5x
Net debt to EBITDA (12/23E)	5.8x

EPS (UBS, diluted) (US$)

	12/23E	
	UBS	Cons.
Q1	0.70	0.70
Q2	0.41	0.41
Q3	0.67	0.67
Q4E	0.58	0.58
12/23E	2.36	2.36
12/24E	2.54	2.51
12/25E	2.77	2.72

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What Happened?

The Illinois Commerce Commission issued it's ruling in Exelon's ComEd multi-year rate plan filing today. The ICC deemed ComEd's grid plan deficient under what is called for in the Climate and Equitable Jobs Act and rejected it, requesting the company to refile within three months. While the capex and rebase numbers will have to determined in the subsequent refile the commission authorized a ROE of 8.95% and an equity ratio of 50%.

What's Our Take?

The actions taken by the ICC today call into question, in our view, the regulatory backdrop in which EXC operates. We are reviewing our earnings and valuation for EXC given the development. The stock is reacting to a well below average ROE and the lack of knowing what the amount of capex and rate base will be over the next four years. As a sensitivity, every 50bps of ROE is worth ~$0.04/shr and every $100mm of rate base is worth $0.01/shr.

What's Next?

The company will need to refile the grid plan with the next three months. Exelon is also awaiting a final decision in it's BG&E case today in Maryland.

Valuation:

We have placed our rating and price target under review.

Highlights (US$m)	12/20	12/21	12/22	12/23E	12/24E	12/25E	12/26E	12/27E
Revenues	15,436	17,938	19,078	18,406	18,970	19,644	20,365	21,063
EBIT (UBS)	2,554	2,682	3,315	3,902	4,155	4,489	4,867	5,227
Net earnings (UBS)	1,740	1,791	2,239	2,353	2,540	2,775	2,976	3,227
EPS (UBS, diluted) (US$)	1.78	1.83	2.27	2.36	2.54	2.77	2.96	3.19
DPS (net) (US$)	1.16	1.35	1.35	1.44	1.55	1.67	1.79	1.91
Net (debt) / cash	(31,684)	(33,868)	(38,960)	(43,038)	(45,723)	(48,682)	(51,315)	(53,548)
Profitability/valuation	**12/20**	**12/21**	**12/22**	**12/23E**	**12/24E**	**12/25E**	**12/26E**	**12/27E**
EBIT (UBS) margin %	16.5	15.0	17.4	21.2	21.9	22.9	23.9	24.8
ROIC (EBIT) %	4.7	4.2	4.8	5.7	5.7	5.9	6.0	6.2
EV/EBITDA (UBS core) x	13.5	14.4	11.8	9.8	9.1	8.5	7.9	9.4
P/E (UBS, diluted) x	22.4	25.7	19.7	16.3	15.2	13.9	13.0	12.1
Equity FCF (UBS) yield %	(7.3)	(10.8)	(5.2)	(7.5)	(3.2)	(3.5)	(2.8)	(1.4)
Dividend yield (net) %	2.9	2.9	3.0	3.7	4.0	4.3	4.6	5.0

Source: Company accounts, LSEG Eikon, UBS estimates. Metrics marked as (UBS) have had analyst adjustments applied. Valuations: based on an average share price that year, (E): based on a share price of US$ 38.59 on 14-Dec-2023 14:38:01 EST

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Forecast returns

Forecast price appreciation	23.7%
Forecast dividend yield	4.1%
Forecast stock return	27.8%
Market return assumption	9.4%
Forecast excess return	18.3%

Company Description

Exelon owns six regulated utility subsidiaries: Atlantic City Electric, BGE, ComEd, Delmarva Power, PECO and the Pepco Subsidiaries, which deliver electricity and natural gas to about 10m customers in Delaware, Washington DC, Illinois, Maryland, New Jersey, and Pennsylvania.

Valuation Method and Risk Statement

Our valuation methodology for the group is price to earnings based. The adjustments applied fall into 5 categories. These are as follows: 1) Group Valuation Bias: Flowing from our valuation work comparing Baa corporate yields to group dividend yields and RU price to earnings ratios to those for the S&P 500, we incorporate a positive or negative adjustment to our group multiple representing the gap we calculate to the nearest 5%; 2) Growth Adjustment: We adjust our valuations based on the growth quartile each utility occupies. First quartile receives a 5% premium, second quartile a 2% premium, third quartile a 2% discount and fourth quartile a 5% discount; 3) Regulatory Adjustment: Our valuation adjustments for regulation are based on our proprietary Regulatory Rankings. First quartile jurisdictions receive 5%, second quartile 2%, third quartile -2% and fourth quartile -5%; 5) Multi Utility Diversified Valuation: For multi utilities (those with more than 15% diversified or foreign earnings), we perform a sum-of-parts analysis applying business/region appropriate valuations to those diversified businesses; 6) One-off Adjustments: In special situations, we value risk on an issue specific basis. Common areas where we apply such an adjustment include: ESG advantage, large project construction risk, legal risk, and announced M&A completion risk.

We have placed our rating and price target under review. Our Price Target of $47 premised on a 6% premium to the group multiple or 17.0x our $2.77/share earnings forecast for 2025.

Specific risks for Exelon include regulatory risks at the utilities, weather, and interest rates.

Quantitative Research Review

UBS Global Research publishes a quantitative assessment of its analysts' responses to certain questions about the likelihood of an occurrence of a number of short term factors in a product known as the 'Quantitative Research Review'. The views for this month can be found below. Views contained in this assessment on a particular stock reflect only the views on those short term factors which are a different timeframe to the 12-month timeframe reflected in any equity rating set out in this note. For previous responses please make reference to (i) previous UBS Global Research reports; and (ii) where no applicable research report was published that month, the Quantitative Research Review which can be found at https://neo.ubs.com/quantitative, or contact your UBS sales representative for access to the report or the Quantitative Research Team on qa@ubs.com. A consolidated report which contains all responses is also available and again you should contact your UBS sales representative for details and pricing or the Quantitative Research Team on the email above.

Exelon Corp

Question	Response
1. Is the industry structure facing the firm likely to improve or deteriorate over the next six months? Rate on a scale of 1-5 (1 = getting worse, 3 = no change, 5 = getting better, N/A = no view)	4
2. Is the regulatory/government environment facing the firm likely to improve or deteriorate over the next six months? Rate on a scale of 1-5 (1 = getting tougher 3 = no change, 5 = getting better, N/A = no view)	3
3. Over the last 3-6 months in broad terms have things been improving/no change/getting worse for this stock? Rate on a scale of 1-5 (1 = getting a lot worse, 3 = not much change, 5 = getting a lot better, N/A = no view)	4
4. Relative to the current CONSENSUS EPS forecast, is the next company EPS update likely to lead to: (1 = negative surprise vs consensus, 3 = in-line with consensus, 5 = positive surprise vs consensus expectations, N/A = no view)	3
5. What's driving the difference?	
6. Relative to YOUR current earnings forecast, is there relatively greater risk at the next earnings result of:(1 = downside skew risk to earnings, 3 = equal upside or downside risk to earnings, 5 = upside skew risk to earnings, N/A = no view)	3
7. What's driving the difference?	
8. Is there an upcoming catalyst for the company over the next three months?	
9. Is there an actual or approximate date for the catalyst?	
10. Is the catalyst date an actual or approximate date?	
11. What is the catalyst?	

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12-Month Rating	Definition	Coverage[1]	IB Services[2]
Buy	FSR is > 6% above the MRA.	54%	40%
Neutral	FSR is between -6% and 6% of the MRA.	38%	42%
Sell	FSR is > 6% below the MRA.	9%	40%
Short-Term Rating	**Definition**	**Coverage[3]**	**IB Services[4]**
Buy	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%
Sell	Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%

Source: UBS. Rating allocations are as of 30 September 2023.
1:Percentage of companies under coverage globally within the 12-month rating category.
2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
3:Percentage of companies under coverage globally within the Short-Term rating category.
4:Percentage of companies within the Short-Term rating category for which investment banking (IB) services were provided within the past 12 months.

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UBS Securities LLC: Ross Fowler, CFA, William Appicelli, CFA.

Company Disclosures

Company Name	Reuters	12-month rating	Price	Price date
Exelon Corp[2,4,5,16,7,6a,6b]	EXC.O	Buy	US$41.00	13 Dec 2023

Source: UBS Global Research; LSEG Eikon. All prices as of local market close. Ratings in this table are the most current published ratings prior to this report. They may be more recent than the stock pricing date.

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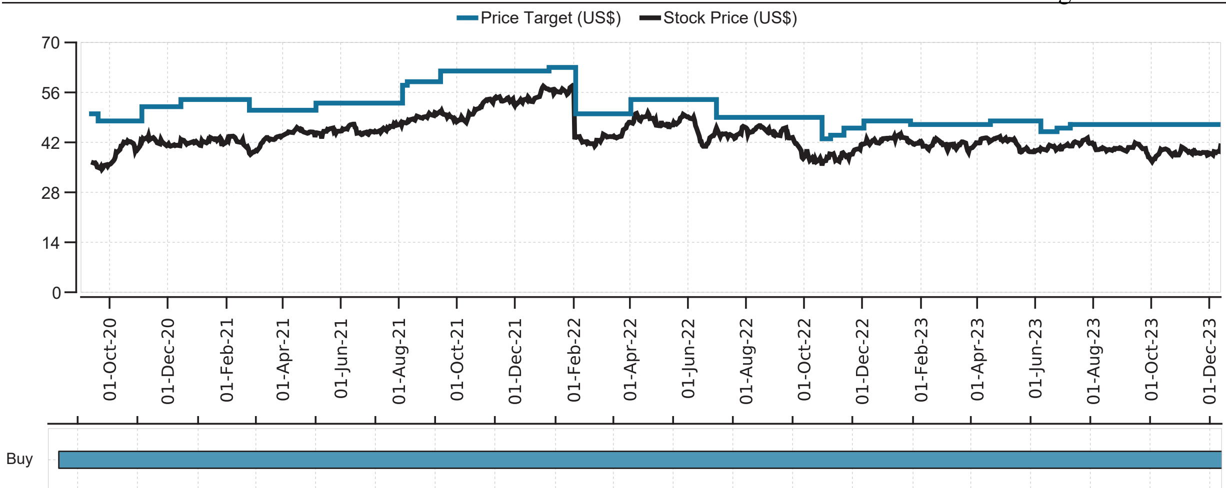
Exelon Corp (US$)



Date	Stock Price (US$)	Price Target (US$)	Rating
2020-09-11	35.83	50.00	Buy
2020-09-18	35.07	48.00	Buy
2020-11-03	42.47	52.00	Buy
2020-12-14	41.06	54.00	Buy
2021-02-24	40.19	51.00	Buy
2021-05-05	43.53	53.00	Buy
2021-08-04	46.77	58.00	Buy
2021-08-09	47.43	59.00	Buy
2021-09-13	50.56	62.00	Buy
2022-01-05	56.97	63.00	Buy
2022-02-02	42.86	50.00	Buy
2022-04-01	47.66	54.00	Buy
2022-06-30	45.32	49.00	Buy
2022-10-19	36.85	43.00	Buy
2022-10-28	38.76	44.00	Buy
2022-11-11	39.11	46.00	Buy
2022-12-02	41.45	48.00	Buy
2023-01-20	42.34	47.00	Buy
2023-04-14	42.13	48.00	Buy
2023-06-06	39.75	45.00	Buy
2023-06-23	39.87	46.00	Buy
2023-07-07	40.96	47.00	Buy

Source: UBS Global Research; LSEG Eikon as of 13-Dec-2023. All prices as of local market close. Ratings as of date shown.

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Price Target Change — December 14, 2023

Regulated Electric Utilities

The ICC Delivers a Lump of Coal for AEE & EXC

Our Call

No mincing words. The ICC's orders on AEE's & EXC's MYRPs & grid plans were onerous and threaten the targeted EPS CAGRs. We reduce estimates and lower our PTs. We maintain our OW on AEE, but shares could be in the penalty box near term.

Grid Plan Rejection. The ICC rejected EXC's & AEE's electric distribution grid plans, citing among a litany of items, a lack of information and supporting data underlying the capital plans. The companies were given three months to re-file. We believe a large portion of EXC's & AEE's '24 IL electric distribution capex relates to the grid plans, so it will be interesting to see how much the companies scale back until clarity is achieved.

MYRP — Low, Low, Low ROEs. Maybe we should have seen this coming after the recent natural gas utility rate orders (9.4-9.5% ROEs vs. the ALJ rec. of ~9.8%). However, we view the clean energy transition as a priority in IL and thought the ICC was likely to adopt the ALJ rec. of 9.24% (AEE) & 9.28% (EXC). Not the case! Instead, the ICC approved low allowed ROEs of 8.72% (AEE) & 8.905% (EXC). These are among the lowest ROEs approved in '23 and are well below the national average of ~9.5%.

Our Thoughts. We now view IL as one of the worst regulatory jurisdictions in the U.S. (nipping at CT's heels). We think the totality of the recent orders suggest that the regulatory balancing act between customers and investors is currently heavily skewed toward customers. As a result, we wonder if AEE & EXC will allocate capital away from IL. Keep in mind, IL represents ~25% of both AEE's & EXC's total rate base.

AEE. We lower our 24-27E EPS to/from $4.50/$4.70, $4.85/$5.05, $5.15/$5.40 & $5.50/$5.70. The revised outlook results in a 6% CAGR, which is at the low end of the 6-8% guidance. We think there could be factors that mitigate the EPS impact (pull forward of capex and/or re-allocation of capital away from IL). We will likely have more clarity on the Q4 release (capex refresh, etc.). We lower our PT to $84 from $86 premised on a 0-5% P/E multiple premium to peers vs. a 10% premium previously.

EXC. We lower our 24-27E EPS to/from $2.43/$2.50, $2.65/$2.73, $2.81/$2.92 & $3.00/$3.11. The outlook results in a 6% CAGR, which is at the low end of the 6-8% guidance. Like AEE, there could be factors that mitigate the impact of the IL orders. Lastly, we lower our PT to $41 from $42 premised on a 5% P/E multiple discount to peers vs. an in-line multiple previously.

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Financials

$ Company Name (Ticker)	Rating Curr.	Rating Prior	Price 12/14/23	FY EPS 2022A	FY EPS 2023E Curr.	FY EPS 2023E Prior	FY EPS 2024E Curr.	FY EPS 2024E Prior	FY P/E 2023	FY P/E 2024	Price Target To	Price Target From
Regulated Electric Utilities												
Ameren Corporation (AEE)	OW	NC	$75.02	4.14	4.38	NC	4.50	4.70	17.1x	16.7x	$84.00	$86.00
Exelon Corporation (EXC)	EW	NC	$37.90	2.27	2.38	NC	2.43	2.50	16.0x	15.6x	$41.00	$42.00

Source: Company data and Wells Fargo Securities, LLC estimates, and Refinitiv.
OW = Overweight, EW = Equal Weight, UW = Underweight, NR = Not Rated, SR = Suspended
NA = Not Available, NC = No Change, NE = No Estimate, NM = Not Meaningful

AEE Earnings Model ($ millions except per share data)	2022	2023E	2024E	2025E	2026E	2027E
Revenues	**$7,957**	**$8,280**	**$8,546**	**$8,933**	**$9,320**	**$9,744**
Expenses						
Purchased Power/Fuel/Power Cost Adjustments	1,547	884	889	893	898	902
Fuel Expense	473	1,138	1,143	1,148	1,152	1,157
Other O&M	1,937	1,913	1,933	1,964	1,997	2,032
Depreciation & Amortization	1,289	1,389	1,505	1,632	1,772	1,915
Gas for Resale	657	684	687	689	691	693
Other	539	541	550	558	568	577
Total Expenses	**$6,442**	**$6,550**	**$6,706**	**$6,884**	**$7,077**	**$7,276**
EBIT	**$1,515**	**$1,730**	**$1,840**	**$2,050**	**$2,243**	**$2,468**
EBITDA	**$2,804**	**$3,119**	**$3,345**	**$3,682**	**$4,015**	**$4,383**
Other Income	226	176	175	175	173	175
Interest Expense	486	546	611	676	739	808
Income Taxes	176	191	175	190	201	224
Tax Rate	*14%*	*14%*	*12%*	*12%*	*12%*	*12%*
Earnings						
Income Before Minority Interest & Preferred	$1,079	$1,169	$1,229	$1,359	$1,476	$1,610
Minority Interest & Preferred Dividends	5	6	6	6	6	6
Earnings for common	**1,074**	**1,164**	**1,223**	**1,353**	**1,470**	**1,605**
Avg. Diluted Shares Outstanding	260	266	272	279	286	292
EPS	$4.14	$4.38	$4.50	$4.85	$5.15	$5.50
Non-Recurring	0.00	0.00	0.00	0.00	0.00	0.00
Ongoing EPS	**$4.14**	**$4.38**	**$4.50**	**$4.85**	**$5.15**	**$5.50**
Q1 EPS	$0.97	$1.00A				
Q2 EPS	$0.80	$0.9A				
Q3 EPS	$1.74	$1.87A				
Q4 EPS	$0.63	$0.61				

AEE Supplemental Information	2022	2023E	2024E	2025E	2026E	2027E
Dividend Information						
Dividends Per Share - YE Rate	$2.36	$2.52	$2.67	$2.83	$3.00	$3.18
Dividends Paid Per Share	2.36	2.52	2.67	2.83	3.00	3.18
Payout Ratio	57%	58%	59%	58%	58%	58%
Cash Flow & Balance Sheet Items						
Capital Expenditures (millions)	$3,351	$3,723	$3,639	$4,009	$4,319	$4,294
Book ROE	10.6%	10.6%	10.2%	10.3%	10.3%	10.3%
FFO/Debt	18%	17%	17%	17%	18%	18%
Debt/EBITDA	5.3x	5.1x	5.1x	4.9x	4.8x	4.6x
Common Equity as % of Total Capitalization	41%	41%	42%	43%	43%	44%

Source: Wells Fargo Securities, LLC estimates and company filings

EXC Earnings Model ($ millions except per share data)	2022	2023E	2024E	2025E	2026E	2027E
Revenues	**$19,078**	**$20,161**	**$20,762**	**$21,550**	**$22,321**	**$23,109**
Expenses						
Purchased Power/Fuel/Power Cost Adjustments	6,373	6,392	6,416	6,440	6,464	6,488
Other O&M	4,673	4,529	4,562	4,611	4,645	4,687
Depreciation & Amortization	3,325	3,477	3,730	4,003	4,299	4,599
Other	1,392	1,364	1,388	1,413	1,438	1,463
Total Expenses	**$15,763**	**$15,763**	**$16,096**	**$16,467**	**$16,846**	**$17,238**
EBIT	**$3,315**	**$4,398**	**$4,666**	**$5,083**	**$5,476**	**$5,871**
EBITDA	**$6,640**	**$7,876**	**$8,396**	**$9,087**	**$9,775**	**$10,471**
Other Income	535	255	255	255	250	251
Interest Expense	1,447	1,651	1,597	1,520	1,460	1,403
Income Taxes	349	501	552	600	641	685
Tax Rate	*15%*	*17%*	*19%*	*18%*	*18%*	*18%*
Earnings						
Income from Continuing Operations	$2,054	$2,370	$2,431	$2,670	$2,831	$3,025
Nonrecurring	0	0	0	0	0	0
Adjustment for Non-Controlling Interest	1	0	0	0	0	0
Net Income	**$2,054**	**$2,370**	**$2,431**	**$2,670**	**$2,831**	**$3,025**
Avg. Diluted Shares Outstanding	987	998	1,002	1,006	1,008	1,009
EPS	$2.08	$2.38	$2.43	$2.65	$2.81	$3.00
Non-Recurring	(0.18)	0.00	0.00	0.00	0.00	0.00
Ongoing EPS	**$2.27**	**$2.38**	**$2.43**	**$2.65**	**$2.81**	**$3.00**
Q1 EPS	0.64A	0.70A				
Q2 EPS	0.44A	0.41A				
Q3 EPS	0.75A	0.67A				
Q3 EPS	0.43A	0.60				

EXC Supplemental Information	2022	2023E	2024E	2025E	2026E	2027E
Dividend Information						
Dividends Per Share - YE Rate	$1.35	$1.44	$1.54	$1.66	$1.80	$1.94
Dividends Paid Per Share	1.35	1.44	1.54	1.66	1.80	1.94
Payout Ratio	59%	61%	64%	63%	64%	65%
Cash Flow & Balance Sheet Items						
Capital Expenditures (millions)	$7,147	$7,175	$7,100	$8,225	$8,375	$8,375
Book ROE	7.6%	9.4%	9.2%	9.7%	9.9%	10.2%
FFO/Debt	11%	13%	13%	13%	13%	13%
Debt/EBITDA	6.0x	5.5x	5.3x	5.3x	5.3x	5.3x
Common Equity as % of Total Capitalization	38%	38%	38%	37%	36%	35%

Source: Wells Fargo Securities, LLC estimates and company filings

Acronyms

ALJ - Administrative Law Judge

ICC - Illinois Commerce Commission

MYRP - Multi-Year Rate Plan

Investment Thesis, Valuation and Risks

Ameren Corporation (AEE)

Investment Thesis

Our Overweight thesis reflects AEE's strong 5-yr annual EPS growth prospects of 6%, long runway of capital investment opportunities (including electric transmission projects in MISO) and management's strong financial track record.

Target Price Valuation for AEE: $84.00 from $86.00

Our $84 price target is based on (1) a P/E analysis ($82/sh) (75%)—apply a 0-5% premium to the '24 Regulated Electric median of ~16.5X on our 25E EPS of $4.85 and (2) a three-stage dividend discount analysis ($89/sh) (25%), which employs a ~8% discount rate.

Risks to Our Price Target and Rating for AEE

Risks include the potential failure to achieve earned returns near the utilities' allowed ROEs, regulatory-related risks, particularly in IL, and the risk that upside capex opportunities do not materialize as expected.

Exelon Corporation (EXC)

Investment Thesis

Our Equal Weight rating reflects our view that the current share price adequately reflects EXC's risk/reward proposition. Positive attributes including a healthy projected EPS CAGR (7%) and wires-centric asset mix are balanced by modest balance sheet concerns and our view that the company's regulatory jurisdictions are average to below average.

Target Price Valuation for EXC: $41.00 from $42.00

Our $41 price target is based on a P/E multiple analysis. We apply a P/E of 15X to our 25E EPS of $2.65. Our multiple represents a 5% discount to the '24 Regulated Electric peer group median as we balance positive features (strong 7% EPS CAGR and predominantly electric wires strategy) with our perception that EXC's regulatory jurisdictions are average to below average. We apply the '24 median to our 25E EPS due to the forward-looking nature of our price target.

Risks to Our Price Target and Rating for EXC

Risks to our thesis include favorable/unfavorable regulatory developments (upside/downside) and greater-than-expected ESG appetite for a wires-centric company (upside).

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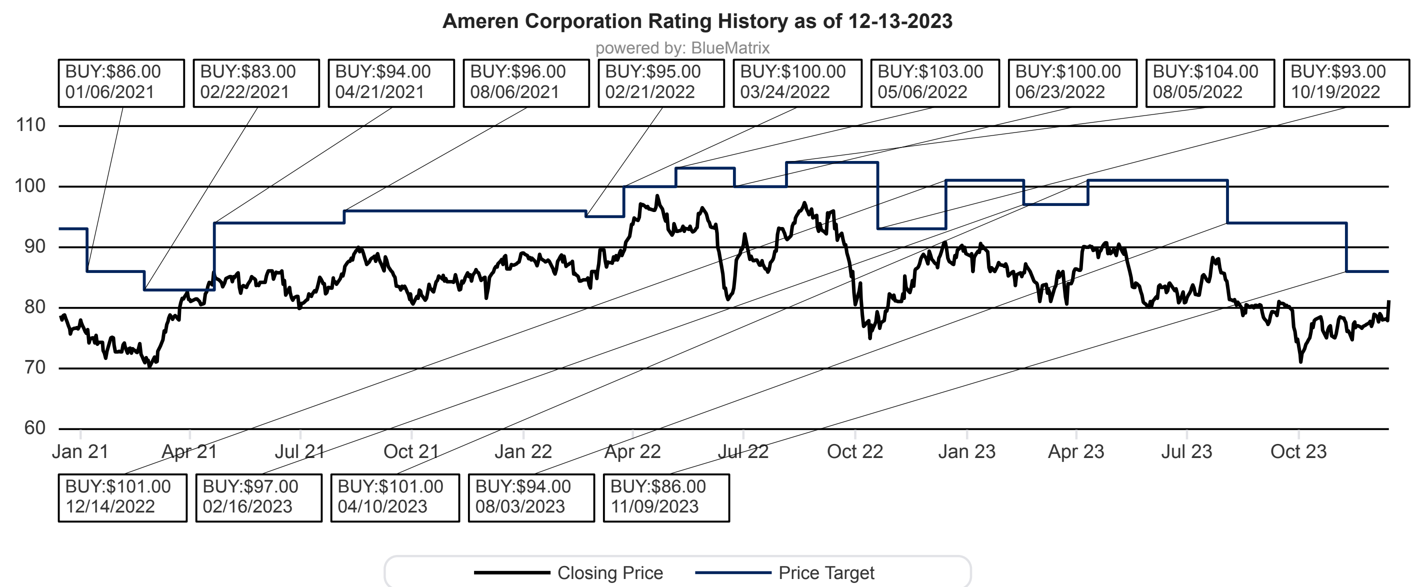

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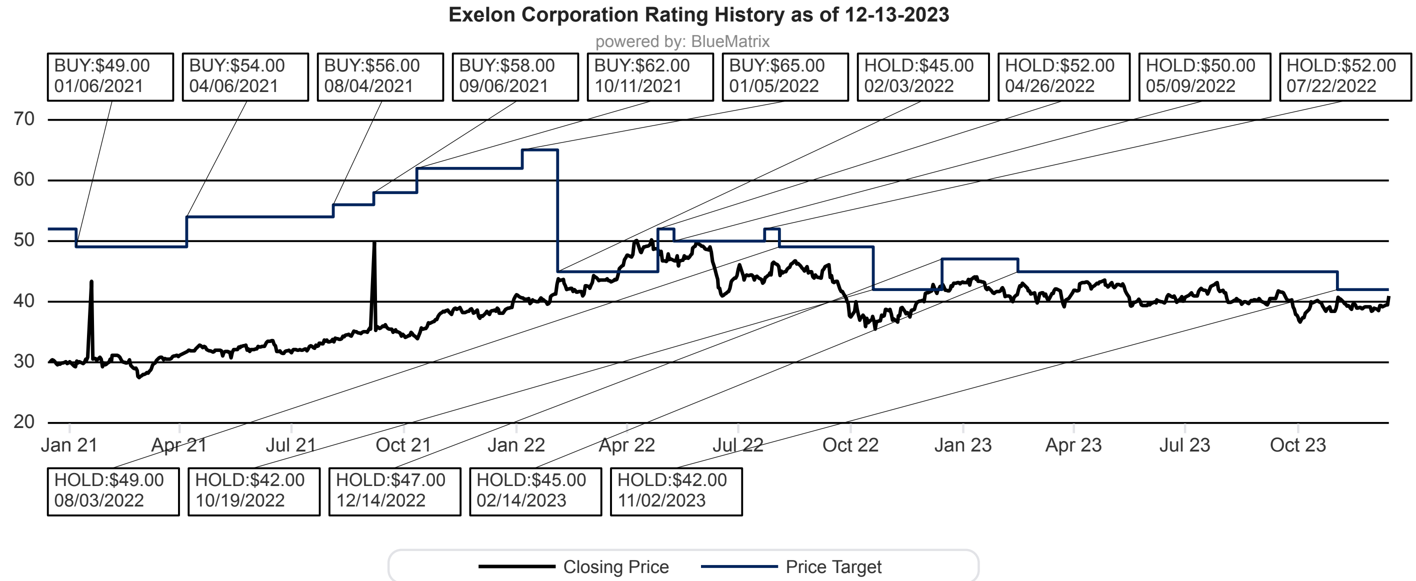

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UW=Underweight: Total return on stock expected to lag the Overweight- and Equal Weight-rated stocks within the analyst's coverage universe over the next 12 months. SELL

NR=Not Rated: The rating and price target has been removed due to lack of fundamental basis to support the recommendation or due to legal, regulatory or company policy considerations.

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Power & Utilities

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IL: Is Illinois Becoming the Next Connecticut? To Be Determined, but Taking a Neutral Stance on the State

Key Message: The ICC delivered a highly disappointing final order in the inaugural EXC and AEE MYPs, creating significant uncertainty over the go-forward earnings power for each utility and cratering investor views of IL as a jurisdiction. As a result, we are downgrading EXC from BUY to NEUTRAL to now align with NEUTRAL rated AEE. While some investors have asked if yesterday's reaction in both names was overdone, we see little reason to remain positive, with 27% of the rate base exposed to the uncertainty of having to re-file the grid plan and a hostile commission. On illustrative math we show below, we see scenarios in which EXC shares may have oversold by 3% (assuming a group multiple), with a $0.11-0.13 impact for '25/26 depending on the assumptions – setting up additional questions on EPS depending on how the capital plans actually unfold. We illustrate a similar outcome of ~$0.11 for AEE shares coming off the meeting; however, we again emphasize that the utility must go through the grid plan process. As a reminder, we were already NEUTRAL rated on AEE. **In totality, we see this as an Illinois issue, not an AEE or EXC issue, with investors in our calls yesterday questioning whether IL was slowly becoming a CT-esque jurisdiction**. In our view, given the potential for a protracted overhang from having to go back and re-file grid plans, equity and debt holders (e.g., agencies for EXC) are going to be wary of IL as a jurisdiction going forward. **We also stress that we don't see this as a management issue – both teams have been good operators and worked through the case process to a manageable proposed order - we hold the utilities in high regard – the ICC is simply sending a negative message to investors.** As a reminder, we had classified IL as a negatively changing jurisdiction in our regulatory baseline earlier this year - see HERE. Again, this is not an AEE or EXC issue, this is an IL issue. Our EXC PT declines to $40 from $44, our AEE PT declines to $73 from $75.

High level take: The ICC issued a disappointing series of data points in its open meeting today for the AEE and EXC MYP final orders, including an 8.72% ROE for AEE and an ~8.905% ROE for EXC – versus investor expectations in our conversations of 9.3-9.4%. The Commission commentary at the open meeting was markedly more negative than our expectations and, to some extent, the ALJ's earlier PO, with oral comments on the final orders indicating that the grid plans (MYIGP), which underpin the spend in the MYPs, will be rejected and will need to be refiled pending further conversations/workshops. **The ultimate EPS impact of any capex disallowances remains difficult to extrapolate without clarity on potential improvement in the subsequent grid plan re-filings; however, we have included some illustrative numbers below on ways in which capital reductions would impact earnings vs. prior expectations.** We caught up with EXC for initial color, which we have included below. We expect to see more releases and have more management calls next week for both companies.

What happened…? In a brisk open meeting, the ICC rejected AEE and EXC's grid plans (MYIGPs) and set an 8.9% and 8.72% ROE, respectively. In the commission's view, the plans were not compliant with parts of CEJA, setting up a refiling process in the coming months (90 days). The commissioners also pointed to specific issues with different parts of the respective capital plans within the grid plans (e.g., IT), setting up uncertainty over what could ultimately be reincluded in the MYP upon refiling/approval. (Note: the commissioners referenced docket 23-0345 in the context of an alternative rate base while the MYIGP goes through its approval process). The orders are available HERE and HERE.

continued...

What do we think…? The move was a surprise - and potentially somewhat overdone - but the trajectory is unequivocally negative from a premium and earnings standpoint. In our view, investors had expected a muted improvement to the ALJ PO ROEs (e.g., towards 9.3-9.4%), with capital and rate base numbers to fall closer to the ALJ's October PO. The rejection of the underlying grid plans scrambles this and sets up an unwelcome waiting period for attaining further clarity well into 2Q24 (90 days to refile, plus a process to re-approve). While we touch on illustrative EPS impact examples below, we see this outcome as a negative from a premia standpoint for both names, **with the ICC's unpredictability and poor outcome here resetting investor views around the state emerging as a premium jurisdiction.** We are removing our prior premiums for IL in our models and moving to a 1x discount on the state in both of our valuations, resulting in a PT decline from $44 to $40 for EXC and $75 to $73 for AEE.

While there is significant uncertainty over the composition of the go-forward capital plan absent a written order for either utility, we note that yesterday's reaction seems at least somewhat harsh on an earnings basis – pulling some $500M/yr out of the current IL distribution capital plan through 2026 and using the ~8.9% ROE would result in a ~$1.5-2/share impact on illustrative simple rate base math for EXC and ~$1.8/share for AEE.

EXC ($B)							
8.9% ROE with Prior Capital/RB							
		2022E	2023E	2024E	2025E	2026E	
Beg RB			13.8	14.8	15.7	16.9	
Capex guided			2.075	2.025	2.35	2.45	
D&A (6.5%)			-1.0	-1.1	-1.2	-1.3	
End RB		13.8	14.8	15.7	16.9	18.1	
ROE			Earnings (50% D/E)				
Investor Expectations	9.30%				0.786	0.841	a
ICC Order	8.90%				0.752	0.805	b
				Earnings Delta	-0.034	-0.036	c = a-b
				EPS Delta	-0.03	-0.04	d = c / sharecount
8.9% ROE and Lower Capital ($B)							
		2022E	2023E	2024E	2025E	2026E	
Beg RB				13.8	14.3	15.1	
Capex (**if lowered $500M/yr**)			1.575	1.525	1.85	1.95	
D&A (6.5%)			-0.1	-1.0	-1.1	-1.1	
End RB			13.8	14.3	15.1	16.0	
ROE	8.90%			Earnings (50% D/E)	0.673	0.711	e
				Earnings Delta	-0.113	-0.131	f = e-a
				EPS Delta vs. 9.3% and *guided* capex	-0.11	-0.13	g = f / sharecount
				group multiple (12/13 close)	15.3x	14.4x	h
				Implied PT change	-$1.7	-$1.9	i = g*h
				Actual Price Change	-$3.10		
				Implied % change ($41 close on 12/13)	-4%	-4.6%	j = i / $41
				Actual % Change	-7.56%		k
				Implied oversold	-2.98%		l = k-j

Source: Guggenheim Securities

AEE ($B)								
8.9% ROE with Prior Capital/RB								
		2022E	2023E	2024E	2025E	2026E		
	Beg RB			3.8	4.2	4.6		
	Capex (guided)			0.72	0.72	0.72		
	D&A (6.5%)			-0.3	-0.3	-0.3		
	End RB		3.8	4.2	4.6	5.0		
ROE			Earnings (50% D/E)					
Investor Expectations	9.30%				0.215	0.232	a	
ICC Order	8.72%				0.202	0.218	b	
				Earnings Delta	-0.013	-0.014	c = a-b	
				EPS Delta	-0.05	-0.05	d = c / sharecount	
8.72% ROE and Lower Capital ($B)								
		2022E	2023E	2024E	2025E	2026E		
	Beg RB			3.8	4.1	4.3		
	Capex (**if lowered 25%**)			0.54	0.54	0.54		
	D&A (6.5%)			-0.3	-0.3	-0.3		
	End RB		3.8	4.1	4.3	4.5		
ROE	8.72%			Earnings (50% D/E)	0.187	0.197	e	
				Earnings Delta	-0.028	-0.035	f = e-a	
				EPS Delta vs. 9.3% and *guided* capex	-0.10	-0.12	g = f / sharecount	
				group multiple (12/13 close)	15.3x	14.4x	h	
				Implied PT change	-$1.51	-$1.77	i = g*h	
				Actual Price Change	-$6.30			
				Implied % change ($81 close on 12/13)	-1.9%	-2.2%	j = i / $41	
				Actual % Change	-7.76%		k	
				Implied oversold	-5.59%		l = k-j	

Source: Guggenheim Securities

We had taken a negative stance on the ICC earlier in 3Q23…. As a reminder, our negative stance on IL at that time was predicated on the degree of turnover at the Commission this year (3 commissioners, including Chair), **the record caseload before the commission, and certain case data points that present potential headwinds to the EDCs.** While CEJA is very prescriptive on the implementation of MYPs, and Chair Doug Scott has been public regarding his involvement in, and support of, the legislation, we remain cautious following Staff's initial testimony for AEE and EXC. In addition, while gas cases this year have generally gone smoothly/favorably (e.g., ~9.89% ROEs), the juxtaposition against more challenging outcomes for the electrics is illogical to us when the state is aggressively seeking to decarbonize – why should the EDCs receive a formulaic ROE 90bps lower than the LDCs? Our concerns around the commission turnover and the record case load (>6) also come against a backdrop of **acute rate pressures in the state and associated political noise** (see our recent note HERE), with over 12% of customer utility bills overdue as of April. **These latest actions, coupled with the illogical gas-electric ROE spread and haphazard MYP case process (Staff formula proposal), place IL firmly within our negative list.**

What's next…? Once the final orders are actually posted and all parties have an opportunity to see the proposed revenue/rate base schedules, we expect the companies to provide additional updates next week, including potential discussions on rehearing requests or other avenues of redress. As a reminder, at our EEI meetings last month (note HERE), EXC was slightly more vocal on this matter vs. AEE, which is not a surprise, in our view, given the proportional weighting of their respective rate bases to IL electric distribution (~27% of EXC '22 RB).

Valuation

We value AEE as a regulated utility, using a SOTP valuation with segment-specific premiums on top of our regulated group multiple of 14x. (1) we attribute a 1x premium on Ameren MO, reflecting potential upside capital opportunities, renewables, and an improving regulatory environment, (2) we assign a -1x discount to IL Electric and IL Gas, and (3) we assign a 4x premium on transmission for growth opportunities in MISO. We apply this to our 2025 EPS estimates for the various segments ($5.05 total for 2025) and discount back to arrive at our $73 PT.

Risks

The primary downside risks encompass traditional risk factors inherent with all utilities including: (1) rate case risk, (2) capex outlook, and (3) interest rate changes above what we account for in our regression model. Company-specific risks include treasury yields deteriorating, further delays on wind construction affecting rate case cadence, further MISO congestion hampering new generation build. Upside risks include capex above levels assumed in our model, more favorable regulatory outcomes, and interest changes below what we account for in our regression model.

Valuation

Our valuation for EXC is based on our 2025E EPS of $2.74. We use our 14x regulated utility multiple, which is based on our regression model using the correlation between electric utility valuations and forward interest rate expectations over the past 30+ years. To this 14x multiple, we apply a 3x premium to all of the utilities, except for ComEd, to reflect our favorable view of the regulatory profile (contemporaneous recovery/minimal lag) and upsides beyond our current plan (aforementioned transmission opportunities). For ComEd, we apply a 1x discount, given the aforementioned issues with the ICC. This 1.6x blended premium (previously 3x), applied to our 2025E EPS and discounted back 1 year equals our $40 PT.

Risks

EXC comprises regulated distribution and transmission assets, which face traditional downside risk factors and drivers inherent with all utilities, including: (1) negative rate case outcomes below our expectations, (2) reduced capex outlooks, and (3) interest rate changes above what we account for in our regression model. Upside risks include capex above levels assumed in our model, more favorable regulatory outcomes, and interest changes below what we account for in our regression model.

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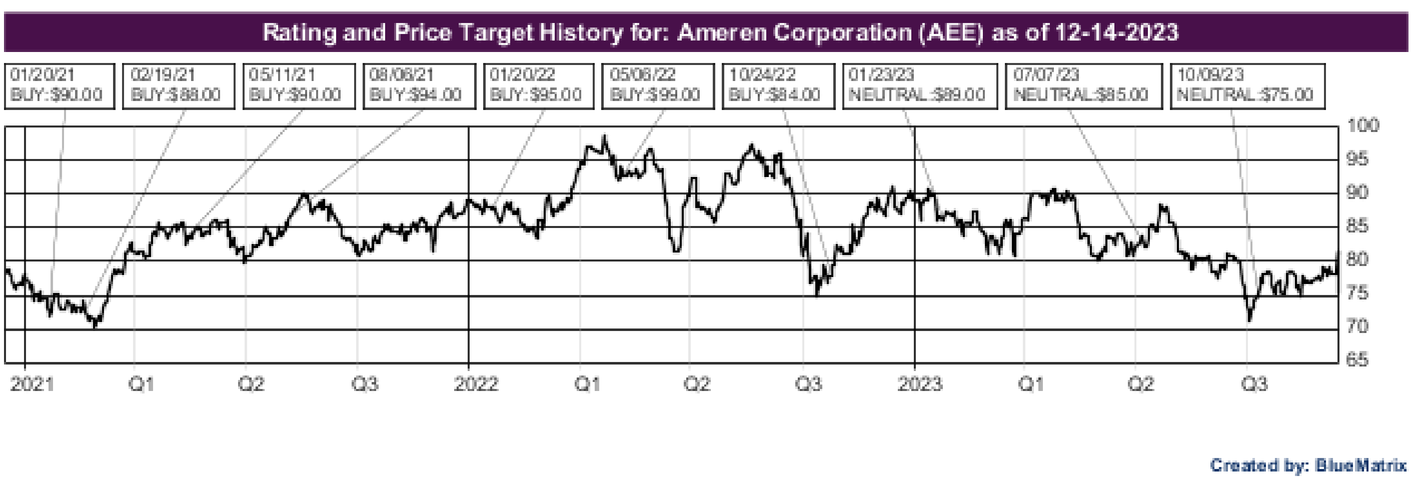

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