DEPARTMENT OF NATURAL RESOURCES
FY 2019-20 JOINT BUDGET COMMITTEE HEARING AGENDA

Friday, December 7, 2018
3:00 pm – 4:30 pm

3:00-3:15 INTRODUCTIONS AND OPENING COMMENTS

Presenters: Bob Randall, Executive Director
Bill Levine, Budget Director

3:15-3:30 WATER RESOURCES REVIEW COMMITTEE BILL

Main Presenter: Bill Levine, Budget Director

Topics:
- Discussion of the Bill: Pages 1-3, Questions 1-2 in the packet, Slides 1-7

3:30-4:00 COLORADO OIL AND GAS CONSERVATION COMMISSION

Main Presenters:
- Doug Vilsack, DNR Legislative Liaison
- Carly Jacobs, DNR Budget Analyst

Supporting Presenters:
- Wendy Schultz, OGCC Finance Manager

Topics:
- General Discussion: Pages 3-5, Questions 3-4 and Attachments A and B in the packet
- R2 Additional Staffing to Address Oil and Gas Backlogs: Pages 5-8, Questions 5-7 in the packet

4:00-4:30 STATE BOARD OF LAND COMMISSIONERS

Main Presenters:
- Bill Ryan, State Land Board Division Director

Topics:
- General Discussion: Page 8-10, Questions 8-9 and Attachment C in the packet

DEPARTMENT OF NATURAL RESOURCES
FY 2019-20 JOINT BUDGET COMMITTEE HEARING AGENDA

Friday, December 7, 2018
3:00 pm – 4:30 pm

WATER RESOURCES REVIEW COMMITTEE BILL

1. *Discuss the benefits of moving Tier 2 Severance Tax Programs, i.e. Natural Resources and Energy Grant Programs, to transfers made in arrears.*

   Response: Statute currently requires funding to be disbursed in three installments over the course of a fiscal year, with the amount of each installment calculated based on the Legislative Council Staff severance tax revenue forecast that immediately precedes it. If a forecast indicates there will not be sufficient revenue to support the full amount of authorized Natural Resources and Energy Grant Programs ("Grant Programs"; formerly Tier 2 Programs) transfers, the installment that follows will be proportionally reduced as necessary to offset the projected revenue shortfall. The current methodology of distributing funding for Grant Programs is based on forecasts, which creates unnecessary complexity and uncertainty given the volatility of severance tax revenue and the difficulty of forecasting it accurately.

   Projected severance tax revenue can change dramatically from one forecast to the next. Even mid-year forecasts, made after 5 months of actual revenue collections, are 36% higher or lower on average than actual total revenue at year-end. Within the last ten years, there have been mid-year forecasts that differed from actual revenue by 100% or more. This creates the potential for Tier 2 disbursements that are too high or too low by a significant amount when judged after actual year-end revenues are known. The most tangible example of the problem with disbursing funding based on projected revenues occurred last fiscal year. Specifically, the June 2017 forecast indicated Tier 2 programs should be funded at 39 percent in FY 2017-18, triggering $5.3 million in Tier 2 distributions in July of 2017. Under the dramatically-lower December 2017 forecast, however, Tier 2 should not have received any funding at all in FY 2017-18 and a portion of the first installment had to be "clawed back" from Tier 2 programs by H.B. 18-1338 to keep the Operational Fund solvent.

   Even though revenue is distributed in installments, Tier 2 programs cannot know how much they will receive with certainty until year-end. In FY 2018-19, no funding can be distributed to Tier 2 programs until the provisions of H.B. 18-1338 are fulfilled. Since this will likely only allow for a single installment of funding at year-end, it provides a ready-made opportunity to transition to an "arrears" model for distributing Tier 2 funding based on actual revenue instead of forecasts. Transitioning to funding Tier 2 programs in arrears would normally require the State to either: (1) provide General Fund to keep Tier 2 programs operational in a transition year (since these programs are used to operating on current year revenue); or (2) live without Tier 2 funding in the transition year. But for FY 2018-19, most or all Tier 2 programs have been operating under the assumption that they would receive no Tier 2 funding at all. Further, most of the highest priority Tier 2 programs received General Fund support in FY 2018-19 through H.B. 18-1338. As such, none of the Tier 2 programs that received General Fund in FY 2018-19 would need any severance tax disbursements, which makes it a perfect time to bank the money and spend it in arrears.

Under the current Legislative Council Staff forecast, an estimated $26.9 million will accrue in the Operational Fund during FY 2018-19 to be available for Grant Programs in FY 2019-20. If this forecast holds, Grant Programs would receive about 74 percent of authorized funding in FY 2019-20. Making a single year-end transfer based on actual revenue removes the uncertainty and computational complexity that comes with being tied to a forecast. It also makes a future "claw back" extremely unlikely because revenue will be distributed on what has been collected, not what is projected. This will allow Grant Programs to plan confidently based on revenue they have in-hand instead of relying on forecasts that will almost certainly be different than actual total revenue at year-end.

2. *What effect will spending severance tax revenue on Tier 2 Programs in arrears have on the volatility of the revenue stream?*

   Response: The proposed move to an arrears model for Grant Programs provides certainty by transferring actual revenue once it's in the Operational Fund, but it does not change the fundamental character of the larger severance tax revenue stream. As mentioned above, statewide severance tax revenue is notoriously volatile, much more so than other energy-dependent revenue streams like the Oil and Gas Conservation Commission levy or federal mineral lease (FML) revenue. From year to year, severance tax revenue goes up or down by an average of more than 82 percent compared to FML, which changes by an average of 26 percent, and the levy, which changes by an average of 23 percent. While severance tax revenue does fluctuate in response to changes in the price and production of oil and gas, the primary driver of volatility is the ad valorem tax credit or offset that allows severance taxpayers to reduce their state severance tax liability by 87.5 percent of ad valorem taxes paid. The credit amplifies volatility because of the time lag between when it is earned and when it is applied.

   Specifically, property taxes are assessed based on production in Year 1, paid in Year 2, and used as a credit against state severance taxes on production that occurs in Year 3. If price and production are strong in Year 1, property taxes paid in Year 2 will be high, which generates a large ad valorem credit or offset to be applied against state severance tax liability in Year 3. If prices and production are much lower in Year 3, severance tax liability will be small to start and reduced further by the substantial credit generated two years prior. The opposite is also true. A weak market in Year 1 would generate a small ad valorem credit that could be applied against severance tax liability in a market boom in Year 3. As a result, the ad valorem credit creates higher highs and lower lows in severance tax revenue than market fluctuations alone.

This volatility also makes severance tax revenue extremely difficult to forecast with accuracy, which is why it is helpful to move Grant Programs away from forecast-based distributions. Moving Grant Programs to transfers in arrears allows them to weather the ups and downs with a little more certainty because the transfers are based on actual revenue in the Operational Fund at the end of year, but it does not change any of the structural factors that make severance tax so volatile in the first place.

Finally, it should be noted that the draft Water Resources Review Committee legislation would increase the target reserves for Grant Programs from the current 15 percent to a proposed 100 percent of authorized spending. While that provision will not change the volatility of the revenue stream, the Department believes this is a prudent change. Grant Programs received zero percent funding from severance tax in both FY 2016-17 and FY 2017-18 (not counting that some programs got General Fund support). Clearly, a 15 percent reserve was insufficient to sufficiently mitigate the multi-year revenue downturn the State just experienced. That stated, it should be noted that increasing the reserve requirement will not inherently put more cash in the Grant Programs' reserve. Grant Programs would have to be fully funded for money to spill over to the Grant Program Reserve, which is not currently projected to happen in the forecast period (through FY 2020-21).

COLORADO OIL AND GAS CONSERVATION COMMISSION

GENERAL TOPICS

3. *Discuss the progress the orphaned wells program has made on plugging and reclaiming wells, including the number of orphan wells awaiting remediation as of the Department's most recent count.*

   Response: In August 2018, the OGCC published the Orphaned Well Program Site List and the Fiscal Year 2018 Annual Report, which collectively summarize program progress and the count of known orphaned wells and sites at the end of FY 2017-18. Specifically, the Site List identified a FY 2017-18 year-end total of 263 orphaned wells and 365 associated orphaned sites yet to be addressed. An orphaned "site" is a location where oil & gas wells or facilities are present and each site may have zero, one, or more individual wells.

   In the first five months of the current fiscal year—July through November 2018—OGCC has completed plugging, equipment removal, reclamation, and various environmental work at 16 orphaned sites, including four well plugging projects. Program staff expanded to include a new engineer, an engineering technician, and a reclamation specialist. Hiring is in progress for the final program position, an environmental specialist. OGCC has also moved forward with deliverables required by [Executive Order D 2018-12] (Attachment A), including the Site List, the Fiscal Year 2018 Annual Report, and a [Financial Assurance Technical Working Group Report] (Attachment B) delivered to the Governor on December 1, 2018. OGCC is also in the process of finalizing guidance to outline a process for oil and gas industry operators to access orphaned wells and orphaned sites to conduct voluntary plugging, remediation, and/or reclamation activities.

As of November 30, 2018, OGCC's current FY 2018-19 Site List includes a total of 248 orphaned wells and 375 associated orphaned sites. Net changes to the Site List do not precisely align with the Orphaned Well Program's reported year-to-date progress because various factors can change the status and number of wells, including: 1) site reactivations to correct for things like weeds or erosion; 2) Federal jurisdiction issues; and 3) project completions (i.e., all production equipment removed, wells plugged, flowlines properly abandoned, environmental remediation performed, surface reclaimed with sufficient vegetation, weeds controlled for multiple growing seasons, and passed final reclamation field inspection by OGCC staff).

4. *Discuss the financial assurance required by the Commission before operators may begin working on a new oil and gas pad and its sufficiency to fund reclamation when operators abandon properties?*

   Response: Every oil and gas operator is required to obtain and maintain financial assurance per OGCC's 700-Series rules before working on a new oil and gas pad or related facility. Financial assurance amounts are based on various factors, including the type of operations performed, the scale of operations, and the depth of wells. The rules provide for both individual sureties and statewide blanket sureties. For example, an operator with two 8,000-foot deep wells would secure two individual well plugging bonds at $20,000 each for a total of $40,000. If the same operator acquired or drilled two additional 8,000-foot deep wells, then it would be more economical for the operator to post a statewide blanket bond for all four wells in the amount of $60,000, the blanket bond amount for operators with less than 100 wells.

   Depending on the activities planned by operators, statewide blanket sureties or individual sureties may be required for the following if appropriate: surface owner protection for unreasonable crop loss or land damage ($2K or $5K per well or $25K blanket); centralized exploration & production waste management facilities (total estimated cost for remediation and reclamation); seismic operations ($25K blanket); well plugging, environmental remediation, and surface reclamation for well sites and production facilities ($10K individual for wells less than 3,000 feet, $20K individual for wells greater than or equal to 3,000 feet, $60K blanket for less than 100 wells, or $100K blanket for 100 or more wells); excess inactive wells (additional sureties for inactive wells at the individual well plugging rates listed above); produced water, gas gathering, and gas storage systems ($5K individual for "small" systems or $50K blanket); and underground injection control facilities ($50K per facility with no blanket option).

A Financial Assurance Technical Working Group convened in Fall 2018 to review the sufficiency of existing financial assurance mechanisms and provide recommendations for revisions to OGCC's financial assurance rules as required by Executive Order D 2018-12. This review included but was not limited to OGCC's current surety amounts. Other funding mechanisms such as sinking funds and pooled bonding were also discussed. The OGCC sent a detailed report to the Governor's Office on December 1, 2018, with recommended actions to ensure sufficient resources are available to conduct remediation and reclamation activities, as well as address current and future orphaned wells and associated oil and gas facilities. The recommendations proposed by the working group include: 1) increase bonding and clarify definitions for inactive wells; 2) develop a risk model for use when wells are transferred from one operator to another; 3) create a plugging, remediation, and reclamation fund; and 4) consider increases to existing bond amounts.

R2 Additional Staffing to Address Oil and Gas Backlogs

5. *Will fully funding the requested positions completely address shortages the Commission has managed in staff over the past several fiscal years that lead to backlogs in many work queues?*

Response: Approving the requested addition of 5.0 FTE and two temporary employees will not eliminate the potential problems discussed in the decision item, but will be an incremental improvement in the right direction. The additional resources would slow the growth of existing backlogs or hold them at a constant level, although progress depends on the rate of the current industry expansion and OGCC's ability to find non-FTE solutions through the development of more eForms, better data management, and Lean initiatives. However, without the additional resources, the OGCC would continue to be reliant on multiple workarounds and short-term temporary resources currently in use, which is not sustainable especially in a multi-year industry growth cycle that is occurring now. This approach is ultimately inefficient and only delays the full impacts of the backlogs instead of reducing them.

The table on the following page shows the growth in backlogs for the regulatory reports discussed in the request. The situation has worsened in the last five months due to the increased volume of reports and recent staff turnover.

Regulatory Form	Backlog as of 6/30/17	Backlog as of 6/30/18	Backlog as of 11/30/18	Percent Change in Backlog (6/30/17 to 11/30/18)
Applications for Permit to Drill (APDs)	1,652	4,890	6,307	282%
Sundry Notices	928	736	1,928	108%
Well Abandonments (Notices of Intent and Subsequent Reports combined)	1,961	1,729	1,817	-7%
Completion Reports	2,051	1,957	2,318	13%

It is important to note that the addition of any new FTE to the OGCC must occur in a balanced fashion because adding staff in one area increases workload for others. For example, field inspectors drive investigative workload for the environmental staff and operational issues for engineering staff. Additional inspectors also lead to the discovery of more violations, hence more workload for enforcement staff. When staffing is out of balance, bottlenecks occur in one or more work units, diminishing the overall effect of additional staff and potentially increasing backlogs further. While the ratio is not one to one—e.g. adding one field inspector does not necessarily require the addition of one full environmental specialist, an enforcement officer, and so forth—without maintaining proper staffing ratios, the OGCC can quickly fall months or even years behind in enforcing suspected rule violations reported by inspectors or other staff members.

6. *Discuss the Department's process for deciding to make this specific request.*

Response: Every spring, members of OGCC's management team prepare justifications for the additional resources they wish to include in the upcoming budget request. For the FY 2019-20 cycle, the managers brought ideas for various new positions to the table. After reviewing the needs of each work unit, the team prioritized and decided to move forward with a conservative request of 5.0 FTE plus funding for 2.0 state temps to provide some level of flexibility. OGCC felt it was a request that most stakeholders would likely agree is necessary, regardless of any changes in direction that a new governor or potential ballot measures would require, and that it is also consistent with the measured approach to staffing the division has always taken due to the cyclical nature of the oil and gas industry. The final request is also balanced in that most OGCC work units experiencing significant increases in workload would get some additional resources to slow or hold the growth of backlogs. The OGCC's request was rigorously reviewed and ultimately approved by DNR's Executive Director's office in June and July before it was submitted to the Governor's office on August 1, 2018.

7. *Discuss permitting fees charged by the Commission.*
   - *Describe fees charged by the Commission,*
   - *Whether they are statutory or administrative,*
   - *The current rates, and*
   - *What would be the effect of increased fees?*

Response: The OGCC has the statutory authority to charge two different types of fees:

a) Service fees of up to $200 for drilling permits, up to $200 for docket items such as hearing applications, petitions, or other pleadings initiating a proceeding, and up to $100 for any protest or other responsive pleading (Section 34-60-106, C.R.S.); and
b) The Oil and Gas Conservation Levy (Section 34-60-122, C.R.S.).

Statute also gives the OGCC the general authority to establish, charge, and collect fees for other services it provides, such as recompletion permits, pit permits, and offsite land treatments. All fees, including the levy discussed below, can be raised or lowered administratively by the Oil and Gas Conservation Commission through the rulemaking process.

Service Fees: The current rate for all service fees is $0, and has been since 1999. Charging fees for services, such as permits, would require software development and, possibly, an FTE to administer. Instead, the levy has been the preferred source of fee revenue due to the simplicity of collecting it and the fairness of the fee.

Oil and Gas Conservation Levy: Section 34-60-122, C.R.S., authorizes the OGCC to assess a levy of up to 1.7 mills on the value of oil and gas production. Operators submit payments on a quarterly basis and the OGCC deposits them into the Oil and Gas Conservation and Environmental Response Fund. The more an operator produces, the more it pays.

The levy was increased to its current rate of 1.1 mills in April 2018. The previous rate of 0.7 mills was effective from July 2007 through March 2018. Over most of that time, rising oil prices and production generated enough revenue to support the OGCC's growing budget. However, revenue decreased with the collapse of oil prices in 2014 and, although prices started increasing again in FY 2016-17, the turnaround was not quick enough or steep enough to shore up the Oil and Gas Conservation and Environmental Response Fund and prevent the first rate increase in over a decade.

Overall, using the levy instead of collecting many small service fees is the most efficient system for OGCC to administer and the easiest for industry to comply with. Though a $200 fee for drilling permits would generate substantial additional revenue, an estimated $1.7 million in FY 2018-19 alone, the same revenue could be collected by increasing the levy rate from 1.1 mills to approximately 1.22 mills. Increased revenue, whether it be through service fees or a higher levy rate, would likely lead to improved service to the industry and/or public safety and the environment, depending on where the additional resources were dedicated. At the current statutory cap of $200 for a drilling permit and hearing application, the reinstatement of these fees is unlikely to impact the number of applications submitted or the level of oil and gas activity.

STATE BOARD OF LAND COMMISSIONERS

8. *Discuss factors contributing to reduced anticipated royalty and bonus payments on lands managed by the Board.*

Response: The State Land Board owns and manages three million acres of land and four million acres of mineral assets. Business operators contract with the State Land Board to lease state trust assets, which generates revenue from agriculture, mineral development, recreation, renewable energy, rights of way, and other uses. Historically, 75% to 90% of State Land Board annual revenue has been generated from the royalties and bonuses paid by minerals developers for the access to, and development of oil, natural gas, and coal. Future mineral revenues are difficult to forecast due to variables outside the State Land Board's control, including commodity market prices and production volume. However, a number of factors lead the State Land Board to believe that revenue from the mineral royalties and bonus payments will decrease over time.

Bonus Payments: Revenue from bonus payments is contingent on demand for access to oil and gas resources on state trust lands. A minerals development company can express interest in developing oil and gas resources on specific trust acreage by nominating that acreage for public auction to the highest bidder. The number of nominations and bids in an auction are an indication of the industry's confidence that oil and gas will be accessible and cost effective to develop on the available acreage. In an auction, the development company will submit an offer for a bonus payment, the extra, up-front premium they are willing to pay to secure access to specific minerals. The number of parcels nominated for auction and the amount of bonuses paid have been declining in recent years, which suggests decreasing demand from development companies as they anticipate a lower probability of finding undeveloped cost-effective sources of oil and gas on state trust land.

Royalty Revenue: Once oil and gas development is underway on state trust lands, the State Land Board receives royalty revenue based on both commodity market prices and production volume. Oil and natural gas prices have decreased significantly compared to the market high in early-2014 and have recently fluctuated over a wide range from under $30/barrel to over $60/barrel. When current market prices are volatile, they impact the future price expectations that the State Land Board uses to forecast royalty revenue. Future price expectations for oil have generally been lower than current market prices, which decreases forecasted royalty revenue going forward. Additionally, when future prices are expected to be low, oil and natural gas development companies will reduce investment in the starting of new wells and supportive infrastructure. This results in two-fold declines in State Land Board revenue because future quantities of oil and gas pulled from trust acreage will be reduced and the royalty received on each unit of oil and natural gas will be lower.

In terms of production, state trust lands earned significant revenue in the early 2010's as a result of the horizontal drilling boom on the Niobrara/Denver-Julesburg basin. The boom occurred because improvements in technology (i.e., hydraulic fracturing) made previously ignored minerals along the Colorado Front Range appealing for development. Wells drilled early in the boom depleted some oil and gas formations quickly and have since produced declining amounts of oil and gas, a trend the State Land Board expects to continue in the future. To compound the issue, production volumes from new wells show significant declines quickly after they come online. To counteract the drop-off in production over time, producers must continually drill new wells to keep oil and gas coming up and generating revenue. The number of new wells being drilled on trust assets each year has been decreasing for several years and is forecasted to continue declining, resulting in future declines in production and the resulting royalties paid to the State Land Board.

9. *Discuss the beneficiaries of revenue generated on the Public School Trust lands.*

Response: Revenue is distributed to the State Land Board's constitutionally-defined beneficiaries based on a statutory formula (Section 22-43.7-104(2)(b)(I)(B), C.R.S.). Each year, the greater of $40 million or 50% of total annual income goes to the School Capital Construction Assistance Fund (the Department of Education's Building Excellent Schools Today program, or BEST). BEST provides funding through a competitive grant program to schools and school districts for the construction and renovation of school facilities. In FY 2017-18, BEST received $64.9 million in State Land Board revenue.

After making the allocation to BEST, the State Land Board deducts its operating expenses and its share of state services—$7.7 million for FY 2018-19—and invests up to $5 million annually to improve and further develop the long term revenue potential of School Trust assets. Any remaining revenue is then deposited into the Public School Permanent Fund, an inviolate trust. For FY 2017-18, the deposit from the State Land Board to the Permanent Fund was $55.5 million.

In FY 2017-18, the Permanent Fund earned a total of $25.5 million in investment income. The distribution of Permanent Fund investment income is also based on a statutory formula (Section 22-41-102(3)(f), C.R.S.). The first $21 million annually is distributed to the Public School Fund, the fund that pays for the Department of Education's operating expenses. A portion of the investment income—about $800,000 in FY 2018-19—is then used to pay for private professional investment fund managers hired by the Public School Fund Investment Board. The Public School Fund Investment Board is a board of investment professionals that was established in 2016 by S.B. 16-035. The purpose of the Board is to direct the state treasurer on how to securely invest money deposited in the Public School Permanent Fund, and by doing so ensure reasonable growth of the Permanent Fund. Any remaining Permanent Fund investment income is then distributed to BEST, and totaled $4.3 million in FY 2017-18.

A diagram of income and distributions of the Whole Trust—the School Trust and Permanent Fund investment income—is included with these responses as Attachment C.

ADDENDUM: OTHER QUESTIONS FOR WHICH SOLELY WRITTEN RESPONSES ARE REQUESTED. PLEASE RETAIN THE NUMBERING IN ORDER TO MAINTAIN CONSISTENT LABELING FOR COMMON QUESTIONS ACROSS DEPARTMENTS.

The Department of Natural Resources has been split into two pieces for JBC briefing and hearing purposes. Written responses to all common questions will be provided as an addendum to the agenda for the "NAT1" hearing, which will cover the Executive Director's Office, Colorado Parks and Wildlife, Colorado Water Conservation Board, and Division of Water Resources. The JBC hearing for NAT1 divisions is currently scheduled for Monday, January 4, 2019.

ATTACHMENT A:

Executive Order D 2018-12

Directing the Colorado Oil and Gas Conservation Commission to Act to Plug, Remediate, and Reclaim Orphaned Oil and Gas Wells and Sites

STATE OF COLORADO

OFFICE OF THE GOVERNOR

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John W. Hickenlooper
Governor

D 2018-012

EXECUTIVE ORDER

Directing the Colorado Oil and Gas Conservation Commission to Act to Plug, Remediate, and Reclaim Orphaned Oil and Gas Wells and Sites

Pursuant to the authority vested in the Governor of the State of Colorado and, in particular, Article IV, Section 2 of the Colorado Constitution, I, John W. Hickenlooper, Governor of the State of Colorado, hereby issue this Executive Order to expand existing efforts to plug, remediate, and reclaim existing orphaned oil and gas wells and sites, and to prevent additional wells and sites from being orphaned in the future.

I. Background, Need, and Purpose

The State of Colorado oversees numerous orphaned oil and gas wells and sites for which no owner, operator, or responsible party presently exists or can be identified, or where such owner, operator, or responsible party is unwilling or unable to conduct plugging, remediation, or reclamation. The Colorado Oil and Gas Conservation Commission ("Commission") is currently tracking 262 orphaned wells that require plugging and 373 associated orphaned sites that require remediation and/or reclamation. The Commission estimates that the total cost to plug, remediate, and reclaim these orphaned wells and sites is over $25 million.

The number of oil and gas operators that have filed for bankruptcy or do not have the funds to operate in compliance with the law continues to increase. These and other operators have and will continue to add new orphaned wells and sites to the existing orphaned wells and sites. In addition, hundreds of undiscovered orphaned wells are located in historic oil and gas fields around the State, such as the Florence and Rangely fields.

On a per-well basis, Commission data show the average cost to plug an orphaned well is six times greater than the amount of financial assurance held by the State. If costs to remediate environmental impacts and reclaim an orphaned site are included, the average actual costs exceed available financial assurance by a factor of fourteen. The Commission currently lacks the resources necessary to cover this deficit in financial assurance and to plug, remediate, and reclaim known orphaned wells and sites and orphaned wells and sites that will be identified in the future. As a result, the State's number of orphaned wells and sites is steadily increasing, and will continue to do so under the current system of financial assurance.

A more coordinated effort, in collaboration and cooperation with industry and advocacy partners, to plug, remediate, and reclaim orphaned wells and sites, and prevent future orphaned wells and sites, will improve the environment, public health, and safety of Coloradans.

II. Definitions

"Orphaned Well" means a well for which no Owner or Operator can be found, or where such Owner or Operator is unwilling or unable to plug and abandon such well.

"Orphaned Site" means a site, where a significant adverse environmental impact may be or has been caused by oil and gas operations for which no responsible party can be found, or where such responsible party is unwilling or unable to mitigate such impact.

"Operator" means any person who exercises the right to control the conduct of oil and gas operations.

"Owner" means the person who has the right to drill into and produce from a pool and to appropriate the oil or gas produced therefrom either for such owner or others or for such owner and others, including owners of a well capable of producing oil or gas, or both.

III. Declaration and Directives

A. I hereby declare that it shall be the goal of the State of Colorado to achieve the following:

1. A reduction in the number of medium- and high-priority Orphaned Wells and Orphaned Sites in the State to zero;

2. Engagement of the oil and gas industry in the plugging, remediation, and reclamation of Orphaned Wells and Orphaned Sites; and

3. A system of financial assurance that prevents future Orphaned Wells and Orphaned Sites by providing sufficient funding for plugging, remediation, and reclamation activities.

B. The Commission shall update its comprehensive list of all Orphaned Wells and Orphaned Sites known to exist on August 1, 2018 and shall update the list on July 1 in each subsequent year. The Commission shall prioritize the list of Orphaned Wells and Orphaned Sites into low-, medium-, and high-priority categories based on risk factors, including but not limited to population density, environmental impacts, history of spills or releases, and testing history.

C. The Commission shall use its best efforts to plug, remediate, and reclaim Orphaned Wells and Orphaned Sites, including the removal of equipment, and to reduce the number of medium - and high-priority Orphaned Wells and Orphaned Sites, as developed pursuant to Section III.B., to zero by July 1, 2023.

D. The Commission shall endeavor to plug, remediate, and reclaim any new medium- or high-priority Orphaned Well or Orphaned Site added to the comprehensive list of Orphaned Wells and Orphaned Sites developed pursuant to Section III.B. within two years of its addition to the list.

E. The Commission shall annually report progress on plugging, remediation, and reclamation of Orphaned Wells and Orphaned Sites, including the existing list by September 1 of each year. The report shall be made available to the public, and presented to the Governor and General Assembly committees of reference with oversight authority over the Commission.

F. In accordance with increased spending authority of $5 million as enacted by the General Assembly in Senate Bill 18-1322, the Commission shall adjust the charge authorized under C.R.S. § 34-60-122(1)(a), as necessary, in an amount determined by the Commission to fully conduct plugging, remediation, and reclamation of all medium- and high-priority Orphaned Wells and Orphaned Sites by July 1, 2023.

G. By September 1, 2019, the Commission shall promulgate rules to ensure the sufficiency of financial assurance, including funding plugging, remediation, and reclamation activities for future Orphaned Wells and Orphaned Sites. The Commission shall establish a technical working group to review existing financial assurance requirements and report to the Governor on recommended changes by December 1, 2018.

H. By January 1, 2019, the Commission shall issue guidance regarding the process for Operators to access Orphaned Wells and Orphaned Sites to conduct voluntary plugging, remediation, and/or reclamation activities. This guidance shall include a process for the reimbursement of costs incurred by operators conducting such activities approved by the Commission, including earning a credit against the mill levy as provided for in C.R.S. § 34-60-124(1)(c).

IV. Duration

This Executive Order shall remain in effect until modified or rescinded by a future Executive Order of the Governor.

EXECUTIVE OFFICE · STATE OF COLORADO

GIVEN under my hand and the Executive Seal of the State of Colorado, this 18th day of July, 2018.

John W. Hickenlooper

John W. Hickenlooper
Governor

<u>ATTACHMENT B:</u>

Financial Assurance Technical Working Group Final Report

Submitted to the Governor on December 1, 2018

Executive Order D 2018-12
Financial Assurance Technical Working Group
Final Report
December 1, 2018

Table of Contents

A. Introduction

Governor Hickenlooper signed Executive Order D 2018-12 on July 18, 2018 to improve the environment, public health, and safety of Coloradans by directing the Colorado Oil and Gas Conservation Commission ("COGCC") to plug, remediate, and reclaim orphaned wells and sites and prevent future orphaned wells and sites.[1] The Executive Order requires COGCC to establish a technical working group to review financial assurance requirements and report to the Governor on recommended changes by December 1, 2018. COGCC is then required to promulgate rules by September 1, 2019 to ensure the sufficiency of financial assurance, including funding plugging, remediation, and reclamation activities for future orphaned wells and sites.

The Financial Assurance Technical Working Group ("Working Group") was composed of members with significant experience with Colorado's financial assurance rules and processes, including representatives from local, state, and federal government agencies, the environmental community, the oil and gas industry, and private citizens (*See* Appendix). The Working Group met four times during the fall of 2018 with COGCC and DNR staff to review Colorado financial assurance requirements, best practices in other states, and proposals for modernizing Colorado's financial assurance rules. COGCC gathered information during these meetings for the purpose of developing recommendations for revisions to Colorado's financial assurance rules. Working group members had an opportunity to review and comment on the draft recommendations prior to finalization.

B. Summary of Key Recommendations

Taking into account the Working Group's discussions, COGCC recommends that the following steps be considered in a financial assurance rulemaking in 2019. This rulemaking will ensure that sufficient resources are available to conduct remediation and reclamation activities and address orphaned wells and associated oil and gas facilities, both current and future, in the state of Colorado. COGCC will continue to engage Working Group members to further develop these recommendations prior to the rulemaking.

While the implementation costs of these measures were not evaluated, it is important to note that all will require additional state resources, including increased staffing. Action on these recommendations should also take into account Colorado's strong efforts, compared to other states, to minimize the number of wells that are orphaned. The Commission should also consider the possibility that additional financial assurance requirements for smaller, undercapitalized operators could increase the number of orphaned wells in the short term.

I. Increase Bonding and Clarify Definitions for Inactive Wells

Inactive well bonding drives Colorado's financial assurance system and accounts for the vast majority of all financial assurance for oil and gas wells in the state. COGCC should consider increasing bonding amounts for excess inactive wells above current $10,000/$20,000 levels. The threshold for what constitutes excess inactive wells under Rule 707 should also be lowered, which would require an increase in the amount an operator's total financial assurance is divided by (likely mirroring increases to the $10,000/$20,000 bonding amounts) when calculating the number of excess inactive wells that require additional financial

[1] Executive Order D 2018-12, available at https://www.colorado.gov/governor/2018-executive-orders.

assurance. These actions will incentivize operators to reduce the number of wells they maintain in inactive status.

In addition, the Commission should clarify the definition of an "inactive well," including how it relates to other well status definitions such as "shut-in" and "temporarily abandoned," and clean up related definitions to prohibit efforts to avoid inactive status though activities such as swabbing and selling past production from a tank.

II. Develop a Risk Model for use in Form 10 Transfer Analysis

The Form 10 process presents a clear opportunity for COGCC to review the sufficiency of financial assurance for a specific group of wells, especially adherence to inactive well bonding requirements. In addition to this sufficiency review, COGCC should develop a simple, multi-factor model that identifies assets with high estimated remediation and reclamation costs that could outstrip a new operator's resources and available financial assurance. The model could be made available to operators for use in their due diligence process as well. Higher levels of risk related to inactive wells, inactive equipment, remediation, or reclamation needs could result in additional mandatory bonding at the time of transfer. However, the Commission should take care not to involve COGCC in an assessment of the viability of an operator's business plan, as the agency lacks the expertise to undertake such analysis.

III. Create a Plugging, Remediation, and Reclamation Fund

Increased bond amounts present a financial challenge for smaller operators that must pay cash or provide 100% collateral for their bonds. COGCC should explore alternatives for smaller operators such as the creation of a plugging, remediation, and reclamation fund. Fines and penalty revenue in the Environmental Response Account ("ERA") and some Oil and Gas Conservation Mill Levy ("Mill Levy") funds are already supporting the orphaned wells program, and the Commission has existing authority to implement permit fees up to $200 per application.

The Commission could also request authority from the legislature to charge higher application fees (for example, BLM charges $10,050 per application[2]) or to impose a per-well fee or a per-location fee (for sites without wells) at the time of transfer to a new operator. A portion of any new revenue could stay with the well or location to ensure that funds are available for plugging in the future, and these dollars could be supplemented by a sinking fund or other mechanism to generate additional well-specific or location-specific funds. Some proceeds could also be used by COGCC to address future orphaned wells.

As an alternative to per-well or per-location funds, COGCC should explore the concept of a pooled fund like the Petroleum Storage Tank Fund ("PSTF"). Similar to the PSTF, fees could be raised or lowered depending on the balance of the fund and could be suspended when the fund reaches a maximum allowable amount. The fund would reimburse operators for all or a portion of work related to plugging wells, reclamation, and remediation, after payment of a deductible, as long as the operator is in compliance with COGCC rules and regulations.

[2] BLM Instruction Memorandum 2019-001, available at https://www.blm.gov/policy/im-2019-001.

IV. Consider Increases to Existing Bond Amounts

The Commission should consider increases to per-well and blanket bonding amounts and the creation of more tiers of blanket bonding, as the existing two-tiered structure allows many operators with hundreds, and sometimes thousands, of wells to maintain less than $1,000 of financial assurance per well. Existing $10,000/$20,000 per-well bonding amounts should be raised to correspond with increases to excess inactive well bonding amounts. However, the Commission should refrain from increasing blanket bonding amounts significantly because most companies already maintain excess inactive well bonding that dwarfs blanket bonding amounts. Future increases in bonding amounts should also be scheduled on a regular basis to take into account inflation, though annual increases should be avoided as there are significant transaction costs associated with procuring new bonds.

Additional bonding should also be considered for new sites that will require significant reclamation, such as those with long roads and steep slopes. And blanket and individual bonding or increases to existing bonding levels should be considered for surface owner protection (especially when bonding on to a surface location), underground injection control wells or facilities, and facilities with no wells such as remote tank battery facilities. COGCC should also consider hiring additional staff to assist with bond release requests and related inspections.

Finally, COGCC should conduct financial assurance audits of large operators and a percentage of medium and small operators each year. The agency should also redouble its efforts to provide data about financial assurance, orphaned wells, remediation, and reclamation efforts to the public through its website and in its annual reporting.

C. Existing Financial Assurance Rules and Challenges

C.R.S. § 34-60-106(13) requires oil and gas operators to provide financial assurance to COGCC to demonstrate that they can meet their obligations under the agency's rules. As defined in statute, financial assurance can take the form of a guarantee of performance, certificate of general liability insurance, bond or other surety instrument, letter of credit, certificate of deposit, or other financial instrument, escrow account or sinking fund, or lien or other security interest in real or other property. As reported by COGCC, the vast majority of financial assurance instruments are bonds or other surety instruments, with some operators using certificates of deposit or cash bonds. This is likely because Rule 702 expresses a preference for surety bonds and requires all other instruments to obtain approval by the Commission.

Financial assurance requirements and procedures are set out in COGCC's 700-Series Rules.[3] COGCC claims a bond when an operator fails to perform statutory and regulatory obligations, and releases a bond when an operator has complied with all such obligations. The amount of financial assurance and purpose of different types of bonds within the Commission's jurisdiction are outlined in the table below.

[3] COGCC 700 Series Rules, available at https://cogcc.state.co.us/documents/reg/Rules/LATEST/700Series.pdf.

Table 1: COGCC 700 Series Financial Assurance Rules Overview

Rule 703: Surface Bond	- Provides a monetary award to a surface owner who neither owns the minerals nor has a surface use agreement with the operator for unreasonable crop loss or land damage that cannot be remediated. - Requires a $2,000 (non-irrigated) or $5,000 (irrigated) individual bond by well or a $25,000 state-wide blanket bond.
Rule 704: E&P waste man. facilities bond	- Bonding must equal the total estimated cost to properly reclaim, close, and abandon a facility, including those on federal land.
Rule 705: Seismic operations bond	- Provides for plugging of shot holes and surface reclamation. - Requires a $25,000 state-wide blanket bond.
Rule 706: Plugging Bond	- Provides for protection of the soil, proper plugging and abandonment of the well, and reclamation of the site. - Requires a $10,000 individual bond for a well less than 3,000 feet in total measured depth or $20,000 if equal to or more than 3,000 feet in total measured depth. - Alternatively, requires a $60,000 state-wide blanket bond for less than 100 wells or $100,000 for 100 wells or more.
Rule 707: Inactive Wells Bond	- Provides additional financial assurance for excess inactive wells. - Requires a $10,000 bond for each excess inactive well less than 3,000 feet in total measured depth or $20,000 if equal to or more than 3,000 feet in total measured depth. - Requirements can be modified or waived if the Commission approves a plan for returning wells to production in a timely manner or for plugging wells on an acceptable schedule.
Rule 711: Natural gas Gathering, Processing, or Underground Storage Facilities Bond	- Ensures compliance with rules pertaining to methods of E&P waste management, procedures for spill/release response and reporting, and sampling and analysis for remediation activities. - Was revised in 2018 to include produced water transfer systems. - Requires a $50,000 statewide blanket bond or $5,000 individual bond for small gas gathering systems or processing less than 5 MMSCFD or 700 barrels of water per day.
Rule 712: Bond for Facilities/Structures Associated with Class II UIC wells	- Ensures compliance with rules pertaining to methods of E&P waste management, procedures for spill/release response and reporting, and sampling and analysis for remediation activities. - Requires a $50,000 bond for each facility.

Rule 702 also allows the Director to petition the Commission for an increase in any individual or blanket financial assurance when there is reasonable cause to believe that the Commission may become burdened with the costs of fulfilling the statutory obligations. In addition, Rule 708 requires all operators to maintain general liability insurance of $1,000,000 per occurrence to cover property damage and bodily injury to third parties. Oil and gas operations on federal or tribal lands and on State Trust lands are generally covered by separate bonds.

As a supplement to these financial assurance mechanisms, the COGCC has an emergency response fund of $750,000 annually to address environmental needs. In 2018, the Colorado General Assembly also increased COGCC's spending authority for plugging and reclaiming abandoned wells ("PROW") from $445,000 to $5 million to address the state's backlog of orphaned wells and sites. The revenue that allows COGCC to utilize this spending authority is currently generated from the Mill Levy and, to a lesser extent, from fines and penalties.

COGCC uses any available financial assurance for a particular orphan well or site prior to using funds from the PROW appropriation. Financial assurance, if available, can offset some of the costs for plugging, remediating, and reclaiming orphaned sites. However, financial assurance is often insufficient to complete all necessary work. COGCC estimates that it costs an average of $82,500[4] to plug, reclaim and remediate a single-well orphaned location. In comparison, the average amount of financial assurance available from bond claims for orphan well work done from 2010 through September 2018 was $8,088 per site. This drops to $4,218 per site when taking into account sites with no financial assurance or that did not increase bonding to comply with the 2008 rulemaking.

D. Technical Working Group Discussion Topics

The Working Group met four times to discuss potential changes to COGCC's financial assurance rules and processes. An introductory presentation was provided for each discussion topic. This was followed by an open discussion about the challenges and advantages of that particular approach. The following is a summary of the Working Group's discussions.

I. Risk-Based Models

The Working Group discussed the possibility of developing a risk-based model to determine when operators would be required to increase financial assurance. Case studies of orphaned well projects for Benchmark Energy and Red Mesa Holdings were presented to illustrate specific indicators that could be used to assess the risk of a site becoming orphaned. While inactive well bonding increased over time, it was still insufficient to cover all plugging, waste removal, and equipment removal costs at these sites. In addition, the operator history in both case studies illustrated a pattern of transfers from larger, well-capitalized operators to those with fewer financial resources as production from the wells tapered off.

Current rules contain some consideration of risk through excess inactive well bonding and higher bonding amounts for deeper wells, however a more robust model could be established that takes into account the age of the well, type of well, production curve, testing history, remediation and reclamation liability (tanks, pits, etc.), spill history, and other potential liabilities. Additional bonding or other financial assurance could be required for a well or group of wells as risk increases or at the time of transfer to another operator.

[4] Operators in the Working Group generally agreed that $82,500 was a reasonable estimate for the cost of plugging, reclaiming, and remediating a one-well site, though some stated that their costs were substantially less than COGCC's and varied considerably based on geographic location. Removal of equipment, pits, long roads and other intensive reclamation, and remediation of historic spills are some key cost drivers in orphaned wells projects.

Challenges

- Large/complex risk model for individual wells would take considerable staff time to develop and keep up-to-date.
- Risk model does not work if COGCC does not have correct information from operators.
- Delaying an increase in financial assurance until later in the life of the well misses the opportunity to generate sufficient plugging funds when the well is most productive.

Advantages

- Catches declining wells before they are at risk of becoming orphaned.
- Simple, publicly-available risk model would also be helpful for operator due diligence.

II. Change of Operator / Form 10 Process

The change of operator or "Form 10" process was identified as a key point when wells/operators could be assessed and additional financial assurance could potentially be required. COGCC currently reviews Form 10s to determine that both the buyer and seller are in compliance with Rule 707, including reviewing the buyer for proper bonding to accommodate any inactive wells to be transferred by the seller. COGCC also reviews each line item listed on the Form 10 to ensure that all related liability, such as active pits, spills, and tank batteries, are addressed and/or transferred. Active Remediation projects need to be closed out by the current operator or transferred by the new operator with a supplemental Form 27. Enforcement matters that are open or unresolved may also halt the Form 10 approval process (e.g., Notice of Alleged Violation, Administrative Orders, warning letters).

The group discussed the possibility of additional review through the Form 10 process, noting that the time of transfer was a reasonable point to reassess the viability of a well, a group of wells, or other oil and gas facilities. Some group members also suggested the need for COGCC to obtain additional information about the financial health of the operators involved in the transaction, such as financial statements. The group also acknowledged that the Form 10 process would be an appropriate time to add additional bonding requirements or to implement a risk model.

Challenges

- COGCC does not currently have access to information about the financial health of operators and lacks the resources to assess the viability of operator business strategies.
- Operators often sign agreements to transfer assets before submitting a Form 10.

Advantages

- Could be combined with other strategies like increased bonding or a risk model to prevent larger operators from selling off plugging and abandonment liabilities.

III. Per-well and Blanket Bonding Amounts

Three Working Group participants offered to provide their companies' perspectives of the existing financial assurance system. A smaller operator with just over 100 wells expressed the concern that most private companies have trouble getting bonds without providing substantial collateral. For example, to meet the blanket bond requirement of $100,000 of financial assurance, the operator delivered a $30,000 bond that was procured in 1984 at a premium cost of $250 per year and a $70,000 cash CD. The smaller operator considers that $70,000 to be stranded capital.

A medium-sized operator with over $1 billion in market capitalization was able to obtain surety bonds at a premium of around 2% per year. That operator holds roughly $2 million in bonds to comply with various local, state, and federal requirements. Finally, a representative from a large operator with thousands of wells in Colorado stated that the operator paid $65,000 in premiums each year to obtain $44 million in bonding, a premium of less than 1%.

As of October 2018, COGCC records show $131.8 million in total bonds/financial assurance for 43,474 wells held by 333 operators. 90 operators posted bonds of at least $100,000 (the blanket bond amount for 100 wells or more), with the three most heavily-bonded operators posting total bonds of $44.1 million, $32.5 million, and $4.6 million, respectively. Financial assurance per well ranged from $107 for one larger operator with 935 wells to $100,000 each for two one-well operators. The average financial assurance per well was $3,031.

The Working Group generally agreed that bonding amounts should be reevaluated to ensure that future orphaned wells are addressed. While increases are likely justified if the current tiered system of financial assurance is retained, an analysis of October 2018 financial assurance data shows that doubling the blanket bond amount for 100 plus wells to $200,000 would impact only 14 operators and result in $1,285,000 in additional financial assurance. Even an increase in the 100-plus-well blanket bond to $500,000 would impact only 21 companies and result in $6.7 million in additional financial assurance. This is because total bonding amounts in the state are driven by inactive well bonding, not blanket bonding. Of the 42 operators with 100 plus wells, most have bonds much greater than $100,000.

The group also discussed operator challenges with bond release requests. Every well that has a status of plugged and abandoned, dry and abandoned, or abandoned location is required to pass a final reclamation inspection to have a bond or other financial assurance instrument released. COGCC estimates that there are approximately 1,986 wells encompassing $9.66 million in financial assurance with pending formal bond release requests. COGCC currently has limited staffing to process release requests, so the agency prioritizes requests with completed Form 4s and those with six or fewer wells requiring inspections.

The group had no specific recommendations regarding the per-well and blanket bonding increase that is warranted, preferring to leave that question to rulemaking because any other changes to the financial assurance system could reduce the need to increase bonding.

Challenges

- Surety bonds are inefficient for smaller operators as they require 100% collateral and strand capital that could be used for other business purposes.
- Increases to blanket bond amounts have little impact on the total amount of financial assurance held by the state.
- COGCC has limited staffing to process bond release requests.

Advantages

- Surety bonds are an efficient form of financial assurance for larger operators.
- Surety bonds are usually easy for COGCC to collect and thus provide certainty that the amount of the bond will be available if needed.

IV. Sinking Funds

A sinking fund is an alternative form of financial assurance that was suggested by a number of operators. The concept is that an operator would put regular payments into a fund from the proceeds of production, instead of obtaining a bond and stranding capital up-front. This mechanism could work with single wells or a sinking fund could apply to all of an operator's wells. The fund would stay with the well or group of wells in the event of a transfer to another operator. Sinking funds are currently allowed in statute, but it is the perception of some operators that the Commission would not allow this method of financial assurance.

Challenges

- Development of sinking fund formula could be challenging because too low of a contribution would leave little funds for plugging and too high of a contribution would strand capital for the life of the well.
- Oversight of sinking funds for numerous wells/operators would require significant additional COGCC staffing.

Advantages

- Would address the problem of transferring plugging liability because the sinking fund would be tied to a well.
- An aggressive sinking fund formula could front-load payments to provide significant resources for plugging and reclamation during a well's most productive years.

V. Bonding for Other Aspects of Production

During its third meeting, the Working Group reviewed the main cost drivers for orphaned well projects. Through these discussions, it became clear that high-cost sites usually exhibit similar attributes, such as age of the wells and equipment, challenging pits, steep slopes, long access roads, water issues, extensive tank batteries or flowlines, and a history of spills. As a result, the group considered whether increased scrutiny should be required for sites that exhibit these specific high-risk attributes.

Industry representatives expressed a concern that high reclamation costs for existing orphaned wells were the result of applying modern reclamation requirements to older wells. However, COGCC noted that the agency has a variance process to help address reclamation challenges, and the Commission must comply with its own reclamation rules when addressing orphaned wells and sites. Some participants also noted that more stringent regulatory standards in recent years will minimize plugging and reclamation costs for modern wells and that horizontal drilling concentrates surface impacts so reclamation costs should be smaller. However, it was pointed out that the liability associated with plugging, reclaiming, and remediating a modern multi-well pad is unknown because one has yet to be orphaned.

Challenges

- Establishing separate bonding for other aspects of a site would make the financial assurance system more complicated and could be difficult to administer.

Advantages

- Would increase funds available for sites with high reclamation and remediation costs.

VI. "Inactive Well" and other Definitions

The Working Group reviewed numerous overlapping definitions in regulation and statute related to the state's financial assurance system. There is no definition of "idle well" in Colorado, and many states have different definitions for the term. However, COGCC's 100 Series Rules define an "inactive well" as "any shut-in well from which: no production has been sold for a period of twelve (12) consecutive months; any well which has been temporarily abandoned for a period of six (6) consecutive months; or, any injection well which has not been utilized for a period of twelve (12) consecutive months. The 100 Series also distinguish between a "shut-in well," which could resume production quickly by opening valves and turning on equipment, and a "temporarily abandoned well," which lacks functioning surface equipment or is blocked with downhole plugs, requiring more extensive work to resume production.

Members of the Working Group pointed out that some operators maintain "active" status for wells by selling past production from leasehold tank inventory or by "swabbing" the well to extract and sell a small amount of fluid product each year. Produced water "production" can also currently keep a well "active." While COGCC's production group looks for data that could indicate the use of these techniques, many marginal wells do not receive additional scrutiny. The Working Group discussed the possibility of addressing these issues by revising the definition of "inactive well" to sync with the definition of "stripper well" in statute, and potentially adding new definitions or changing existing definition for a "low flow well," "suspended operations well," and "waiting on completion" well. These new classifications of wells would then be scrutinized during the Form 10 process and perhaps at other times.

Challenges

- Over 70% of wells in Colorado are classified as "stripper wells" in statute, so additional scrutiny of that category of well could require significant new COGCC staffing.
- Additional regulatory burdens placed on a large number of "low flow wells" could result in a significant short-term increase in the number of orphaned wells.

Advantages

- Would clarify regulatory definitions both for COGCC staff and operators.
- Prohibiting techniques such as selling from tank inventory and "swabbing" to maintain "active" status would remove some marginal wells from inactive well bonding and prevent operators from further delaying liability for plugging and abandonment costs.

VII. Pooled Bonding

The group also discussed the possibility of developing a mandatory, operator-supported fund to address future orphaned wells and sites. A representative from the Department of Labor and Employment attended the Working Group's third meeting to provide information about the Petroleum Storage Tank Fund (PSTF), which imposes a fee of up to $100 per load on fuel tanker trucks for the remediation of spills.[5] The fee is raised or lowered depending on the balance of the fund, with the fee diminishing to $0 per load if the balance of the fund exceeds $12 million and climbing to $100 per load if the fund balance is less than $3 million.

The fund reimburses an average of $36 million each year to clean up fuel contamination at gas stations and other facilities. Through this self-insurance process, operators are eligible to receive 100% reimbursement on all costs up to $2 million (after a $10,000 deductible) as long as they are in compliance with rules and regulations. Operators in partial compliance may be eligible to receive partial reimbursement. Over the past five years, the fund has had an average of 167 unique requests for reimbursement, with 13% of the applications on average for newly discovered contamination. Arkansas has a similar abandoned well plugging fund that is separate from its bonding framework, though per-well contributions to the fund are small.[6]

[5] Petroleum Storage Tank Fund overview, available at https://www.colorado.gov/pacific/ops/Fund.
[6] Interstate Oil and Gas Compact Commission, State Financial Assurance Requirements (2016), available at http://iogcc.ok.gov/Websites/iogcc/images/Financial_Assurances_FINAL_web.pdf.

Challenges

- The PSTF is focused on spills, not on challenges associated with facilities at the end of their useful life (i.e. tank removal is currently not reimbursable under the PSTF).
- In the oil and gas context, some operators may rely on the fund instead of maintaining their own funds to address plugging and abandonment.
- Establishing a sizable fund could require statutory authorization and would take time to build up to the desired minimum threshold.

Advantages

- Would provide a predictable source of funding for future orphaned well projects.
- A smaller fund could be created with existing Commission authority, such as the establishment of a $200 permit application fee or a Mill Levy increase.

VIII. Other Alternatives to Bonding

The group discussed a number of alternatives to address orphaned wells using existing resources instead of increased bonding. Some Working Group members suggested that additional funds could be allocated from the Environmental Response Account (a component of the Oil and Gas Conservation Environmental Response Fund) that have accumulated as a result of increased fines and penalties collected by COGCC. COGCC indicated that fines and penalties increased to $1 million in both FY2016-17 and 2017-18. These funds currently support a portion of the orphaned well program, but are insufficient to cover all of the $5M in spending authority granted by the General Assembly. Other alternatives discussed by the Working Group include using Severance Tax and Mill Levy revenue to address orphaned wells.

Challenges

- Other COGCC revenue streams such as fines and penalties, Mill Levy, and Severance Tax revenue are already utilized for orphaned wells or are dedicated to other important programs.
- Existing COGCC revenue streams are highly variable and dependent on market forces.
- Use of Severance Taxes is subject to annual legislative approval and would likely require a redirection of funding from other important programs, such as funds currently used for water projects, forest health, etc.

Advantages

- Would tap existing funding derived from a broad swath of the oil and gas industry.

IX. Other Considerations

The Working Group also briefly considered the following topics that are beyond the scope of this report. While not directly related to financial assurance requirements, further consideration of these tools by COGCC is warranted.

a. Insurance Requirements

One Working Group member, Brad Gibson, presented detailed recommendations for revising Rule 708, including increasing the general liability insurance requirement for operators from $1 million to $5 million per occurrence, requiring sudden and accidental pollution liability insurance, and requiring gradual pollution liability insurance for newly-drilled wells. While not directly related to the orphaned well issue, adequate insurance could help an operator stay in business should an incident occur.

b. Liability of Past Operators

Holding past operators liable for plugging, reclamation, and remediation of orphaned wells and locations was also discussed. BLM representatives provided details about efforts in Wyoming to secure funds from lease holders that had transferred operating rights to other companies.[7] However, COGCC is a regulatory agency and not in the same position as BLM as a mineral lessor. Imposing liability on past operators through a "quasi CERCLA program" that extends liability after the transfer of a well to a new operator would require a statutory change, and additional analysis would be necessary to assess the impacts of this type of measure on the oil and gas industry.[8]

c. Liens on Inventory and Equipment

The Group also discussed the possibility of strengthening the Commission's authority to claim and sell for salvage equipment or product stored at an orphaned site to provide reimbursement for plugging and reclamation costs. This measure would require legislation to provide COGCC with a first priority lean over equipment and product, as opposed to its existing authority to sell product and equipment subject to "any valid liens, security interests, or other legal interests in such equipment asserted by any taxing authority or by any creditor."[9] The Commission rarely uses its existing authority because the undefined process to identify superior interests creates liability concerns for the state. Legislation to provide COGCC with a first priority lien would result in a small amount of additional revenue to address orphaned wells, but would likely face strong opposition from financial institutions.

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[7] *See Monahan v. U.S. Dept. of Interior*, No. 05-8068 (10th Cir. 2007), available at https://cases.justia.com/federal/appellate-courts/ca10/05-8068/05-8068-2011-03-14.pdf?ts=1411084726.

[8] *See* Jacqueline Ho, et al., *Plugging the Gaps in Inactive Well Policy*, Resources for the Future (May 2016), available at http://www.rff.org/files/document/file/RFF-Rpt-PluggingInactiveWells.pdf.

[9] C.R.S. §34-60-124(6)(c)

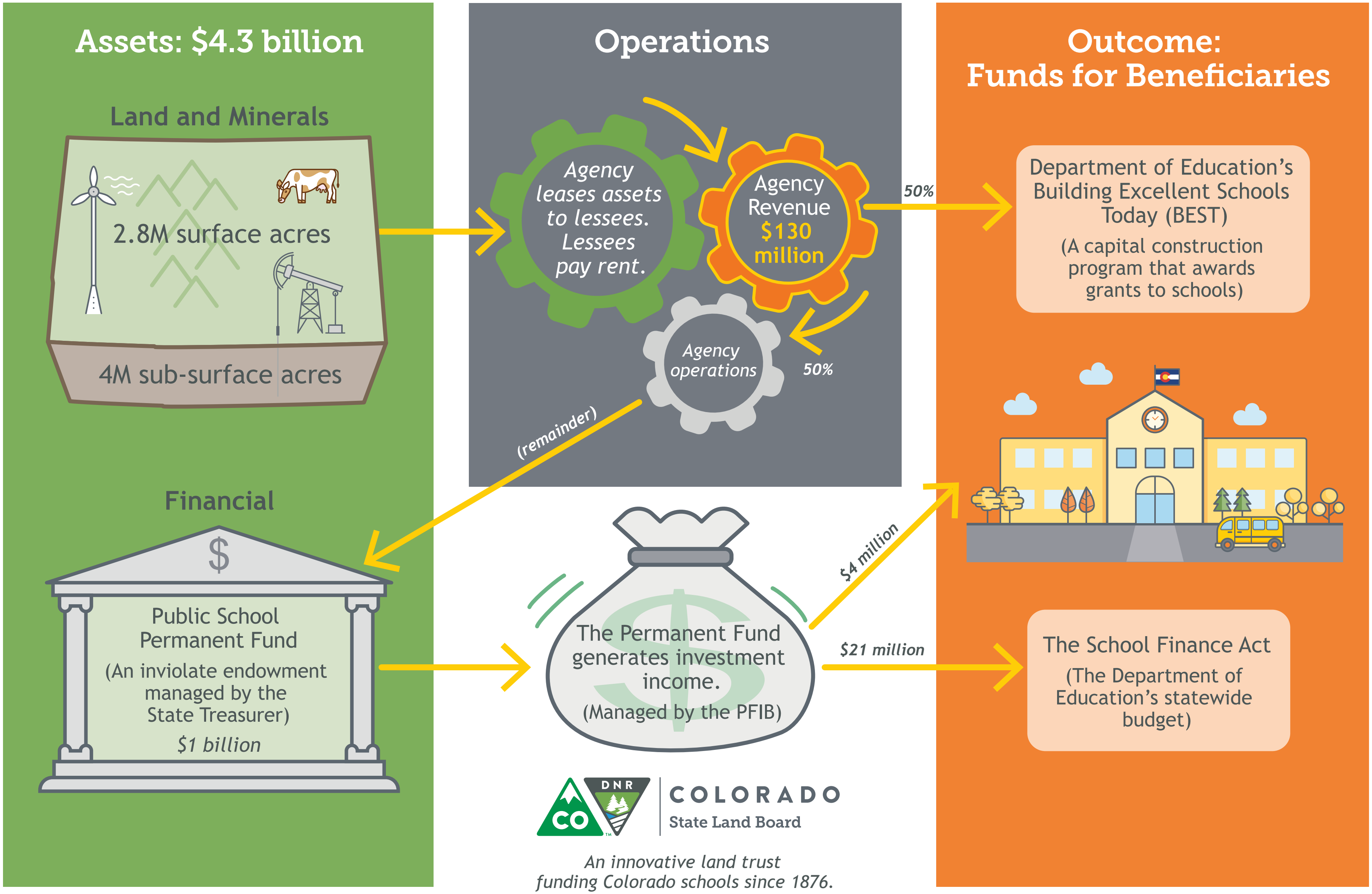
E. Appendix: List of Technical Working Group Participants

- Scott Anderson (Environmental Defense Fund)
- Tracee Bentley (Colorado Petroleum Council)
- Brian Cain (Extraction)
- Chad Calvert (Noble Energy)
- Ashley Campbell (Crestone Peak Resources)
- Andrew Casper (Colorado Oil and Gas Association)
- Morgan Cullen (Colorado Municipal League)
- Jonathan Fairbairn (BLM)
- Brad Gibson (Private Citizen, Broomfield Oil and Gas Task Force)
- Roger Hutson (HRM Resources)
- Warren King (The Wilderness Society)
- Sam Knaizer (BP)
- Dave Kulmann (SRC)
- Jason Maxey (Weld County)
- Kim Mendoza-Cooke (Anadarko)
- Neil Ray (CAMRO)
- Mick Richardson (CO Assoc. of Homebuilders)
- Jep Seman (Conoco)
- Catie Stitt (State Land Board)
- Jimmy Walker (Petron)
- Ken Wonstolen (HighPoint Resources)
- Kirby Wynn (Garfield County)

ATTACHMENT C:

State Land Board Revenue Flow for FY 2017-18

State Land Board Revenue Flow to Schoolchildren (FY 17–18)



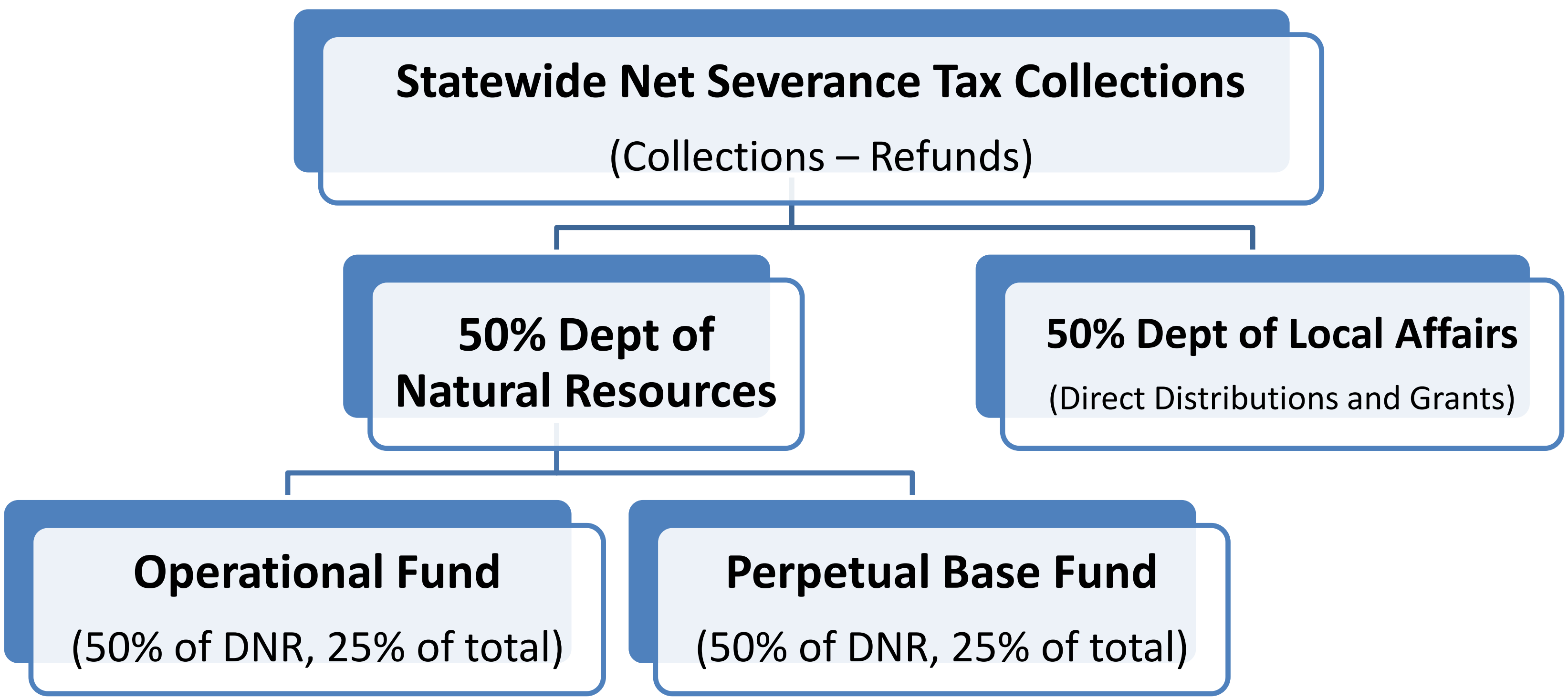
JBC HEARING PRESENTATION

December 7, 2018

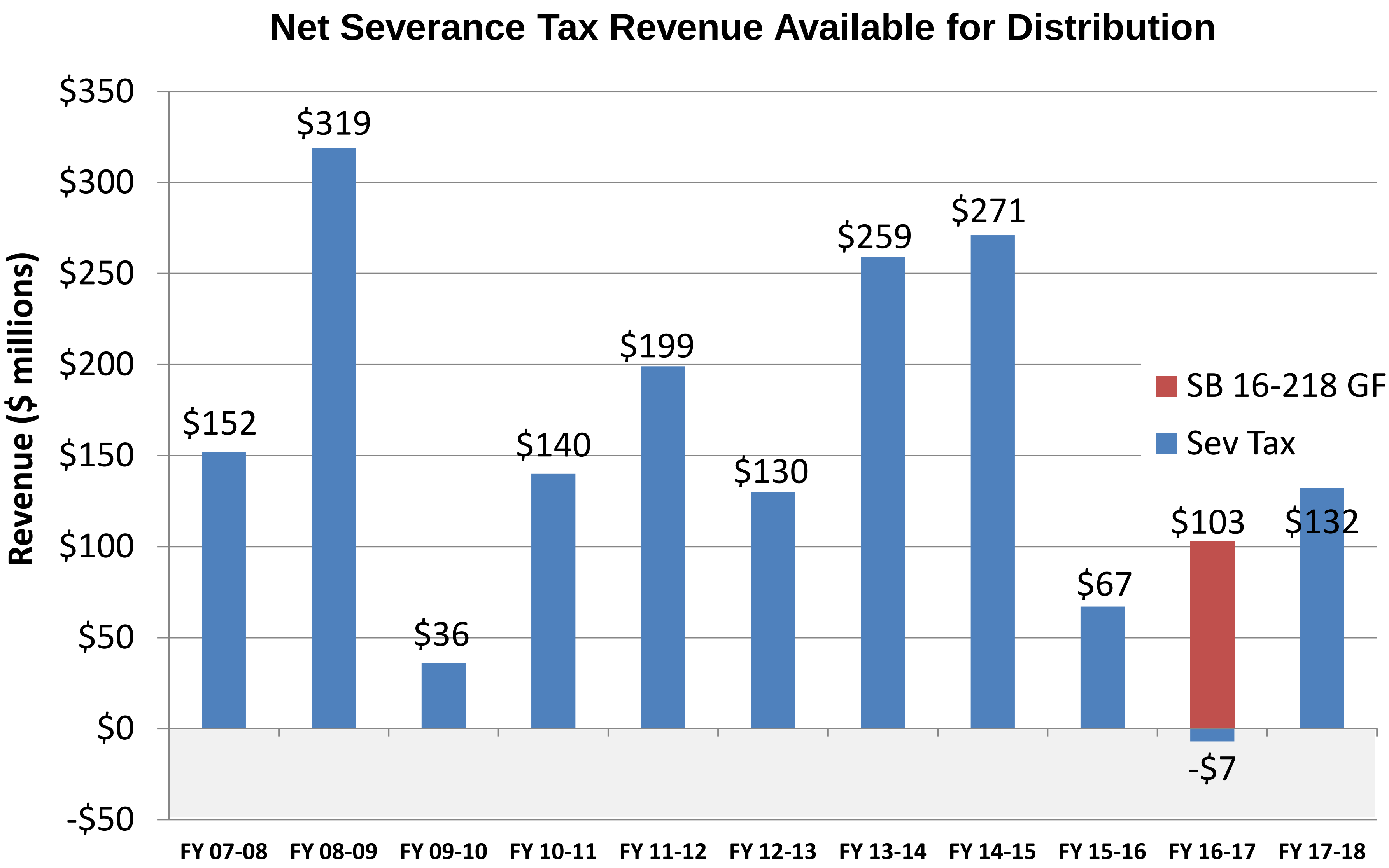
The Severance Tax Roller Coaster

Severance Tax 101

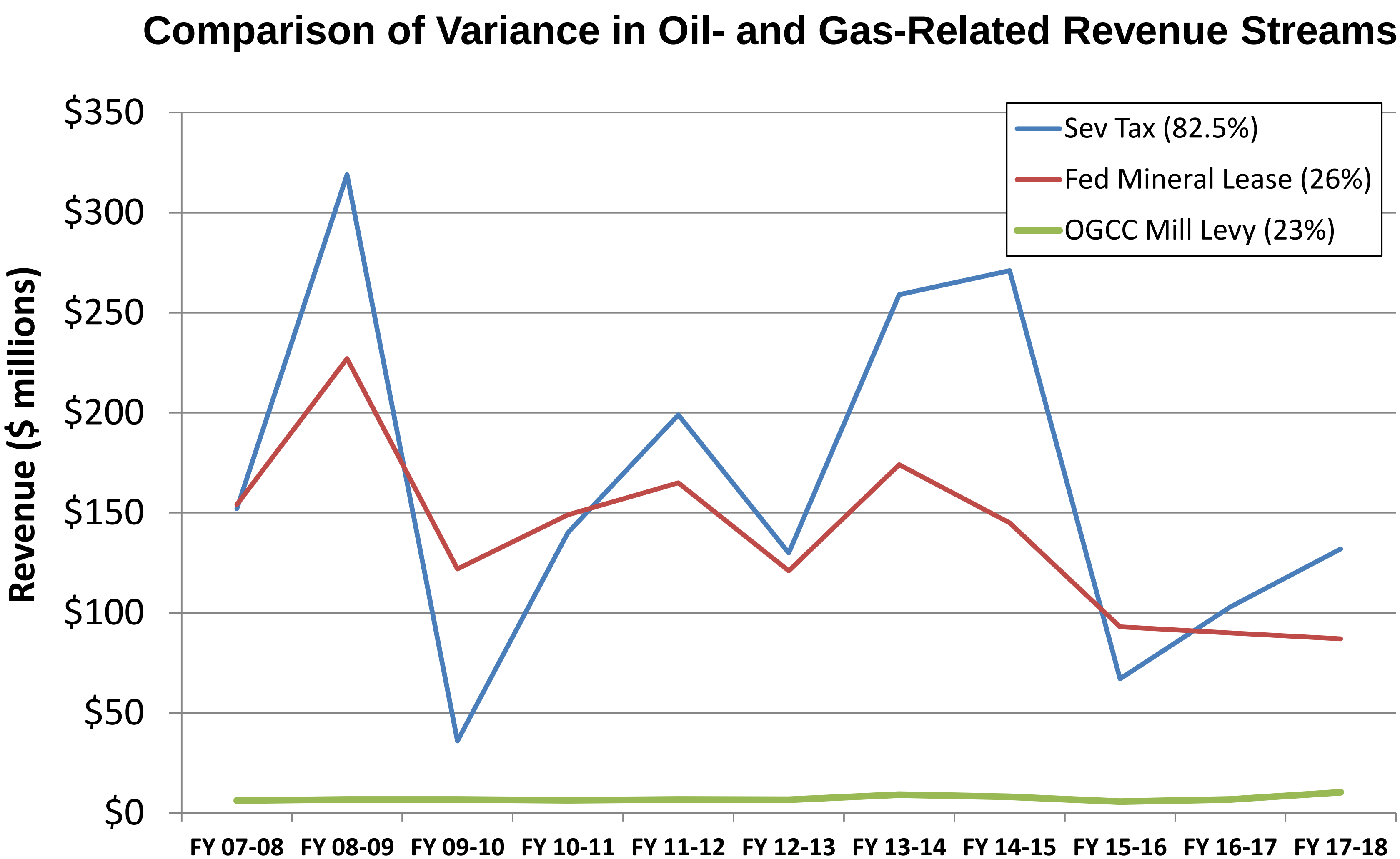
- Colorado collects severance tax on nonrenewable minerals as they are "severed" from the earth.
  - 95% of severance tax revenue = oil and gas



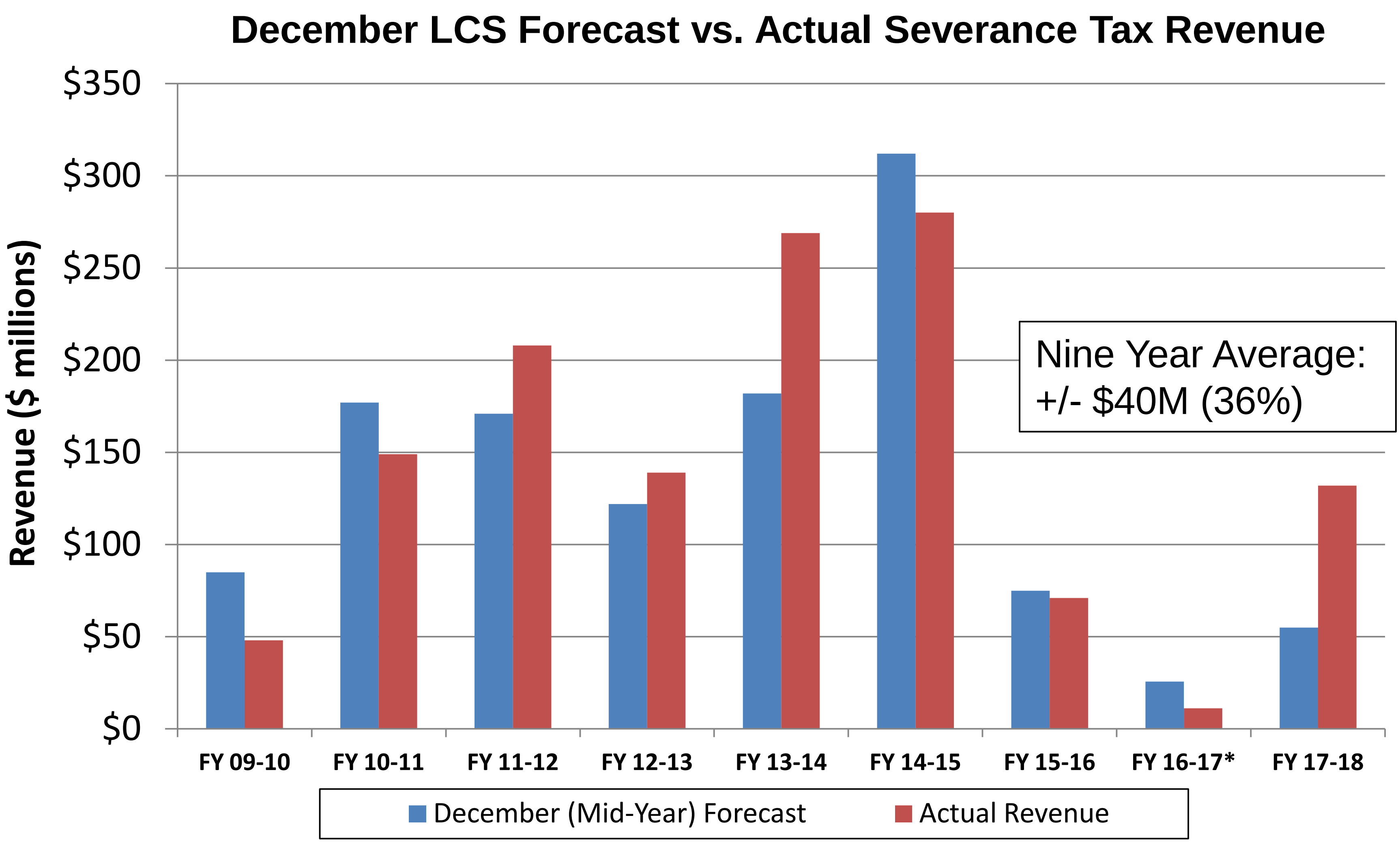
Severance Tax Volatility



O&G-Related Revenue Volatility



Revenue Forecasts v. Actual



*FY 16-17 Dec Forecast was made pre-BP America

Sources of Revenue Volatility

1. Fluctuations in O&G market conditions
2. Property Tax (Ad Valorem) Credit/Offset
   – Operators can take a credit equal to 87.5% of property taxes against state sev tax liability
3. *BP America v. CO Dept of Revenue*

Forecasted FY 2017-18 Severance Tax Revenue

Forecast by Time Period	Amount of Forecast	Installment
June 2017 LCS Forecast	$150 Million	40% of Available Funds to Grant Programs
Dec. 2017 LCS Forecast	$55 Million	30% of Available Funds to Grant Programs
March 2017 LCS Forecast	$70 Million	30% of Available Funds to Grant Programs
Actual FY 2017-18 Revenue	$132 Million	

Notes: All severance tax revenue estimates are from Legislative Council Staff (LCS).